FLORIDA PUBLIC SERVICE COMMISSION

EXHIBIT INDEX

FOR THE HEARING DATED 11/02/2021 IN DOCKET 20210007-EI

Docket No. 20210007-EI
Comprehensive Exhibit List for Entry into Hearing Record
November 2, 2021

Hearing I.D. #	Witness	I.D. # As Filed	Exhibit Description	Issue Nos.	Entered
STAFF					
1		Exhibit List	Comprehensive Exhibit List		
FLORIDA POWER & LIGHT – DIRECT					
2	Renae B. Deaton	RBD-1	Environmental Cost Recovery Final True-up January 2020 - December 2020 Commission Forms 42-1A through 42-9A	1	
3	Renae B. Deaton	RBD-2	Environmental Cost Recovery Actual/Estimated True-up January 2021 - December 2021 Commission Forms 42-1E through 42-9E	2	
4	Renae B. Deaton	RBD-3	Appendix I - Environmental Cost Recovery Projections - January 2022 - December 2022 Commission Forms 42-1P through 42-8P	3-10, 11, 12	
5	Renae B. Deaton	RBD-4	Appendix II - Calculation of Stratified Separation Factors	3-10, 11, 12	
6	Michael W. Sole	MWS-1	2015 Miami-Dade County Department of Environmental Resource Management (“MDC”) Consent Agreement	11	
7	Michael W. Sole	MWS-2	June 2016 FDEP Consent Order	11	
8	Michael W. Sole	MWS-3	2016 MDC Consent Agreement Addendum	11	
9	Michael W. Sole	MWS-4	2019 MDC Consent Agreement Addendum	11	

10	Michael W. Sole	MWS-5	July 2020 Supplemental Salinity Management Plan	11	
11	Michael W. Sole	MWS-6	May 6, 2005 NPDES/IWW Permit Number FL0001562	11	
12	Michael W. Sole	MWS-7	FDEP's April 13, 2020 Notice of Intent to Issue Permit FL0001562	11	
13	Michael W. Sole	MWS-8	FDEP's April 25, 2016 Notice of Violation and Orders for Corrective Action	11	
14	Michael W. Sole	MWS-9	MDC and FPL Agreement	11	
15	Michael W. Sole	MWS-10	Turkey Point Conditions of Certification	11	
16	Michael W. Sole	MWS-11	South Florida Water Management District letter to FPL	11	
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19	Michael W. Sole	MWS-14	Sanford Plant July 13, 2021 Consumptive Use Permit	13	
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GULF POWER COMPANY – DIRECT					
21	Richard L. Hume	RLH-1	Environmental Cost Recovery Final True-up January 2020 - December 2020 Commission Forms 42-1A through 42-9A	1	
22	Richard L. Hume	RLH-2	Environmental Cost Recovery Actual/Estimated True-up January 2021 - December 2021 Commission Forms 42-1E through 42-9E	2	

DUKE ENERGY FLORIDA, LLC – DIRECT					
23	Gary P. Dean	GPD-1	Forms 42-1A - 42-9A January 2020 – December 2020	1	
24	Gary P. Dean	GPD-2	Capital Program Detail January 2020 – December 2020	1	
25	Gary P. Dean	GPD-3	Forms 42-1E – 42-9E January 2021 – December 2021	2	
26	Gary P. Dean	GPD-4	Capital Program Detail January 2021 – December 2021	2	
27	Gary P. Dean Timothy Hill Reginald Anderson Kim S. McDaniel	GPD-5	Forms 42-1P – 42-8P January 2022 – December 2022	3-10	
28	Kim S. McDaniel	KSM-1	Review of Integrated Clean Air Compliance Plan	1-10	
TAMPA ELECTRIC COMPANY – DIRECT					
29	M. Ashley Sizemore	MAS-1	Final Environmental Cost Recovery Commission Forms 42-1A through 42-9A for the period January 2020 through December 2020	1	
30	M. Ashley Sizemore	MAS-2	Environmental Cost Recovery Commission Forms 42-1E through 42-9E for the Period January 2021 through December 2021	2	
31	M. Ashley Sizemore	MAS-3	Environmental Cost Recovery Forms 42-1P through 42-8P Forms for the Period January 2022 through December 2022	3-10	

STAFF HEARING EXHIBITS					
32	Michael W. Sole (2-16)	Staff Exhibit 32	FPL's response to Staff's Second Set of Interrogatories Nos. 2-16 *Bates Nos. 00001-00016*	1, 4, 5, 6, 7	
33	Michael W. Sole (17, 18b, 18c, 22-23) Renae B. Deaton (18a, 19-21)	Staff Exhibit 33	FPL's response to Staff's Third Set of Interrogatories Nos. 17-23 *Bates Nos. 00017-00024*	2, 3, 4, 5, 6, 7, 11, 12	
34	Michael W. Sole (24-27) Renae B. Deaton (27)	Staff Exhibit 34	FPL's response to Staff's Fourth Set of Interrogatories Nos. 24-29 *Bates Nos. 00025-00030*	3, 4, 5, 6, 7, 8, 9, 11, 12	
35	Renae B. Deaton (28)	Staff Exhibit 35	FPL's response to Staff's Fifth Set of Interrogatories No. 28 *Bates Nos. 00031-00035*		
36	N/A	Staff Exhibit 36	Gulf's response to Staff's First Production of Documents No. 1 **(No. 1 has attachments)** *Bates Nos. 00036-00037*	2, 4, 5, 6, 7	
37	Richard L. Hume (1-4)	Staff Exhibit 37	Gulf's response to Staff's First Set of Interrogatories Nos. 1-4 *Bates Nos. 00038-00042*	1, 4, 5, 6, 7	
38	Richard L. Hume (5)	Staff Exhibit 38	Gulf's response to Staff's Second Set of Interrogatories No. 5 *Bates Nos. 00043-00044*	1, 4, 5, 6, 7	
39	Richard L. Hume (6-7, 9-10) Zia Hazari (8)	Staff Exhibit 39	Gulf's response to Staff's Third Set of Interrogatories Nos. 6-10 *Bates Nos. 00045-00051*	2, 4, 5, 6, 7	
40	Kimberly Spence McDaniel (2)	Staff Exhibit 40	DEF's response to Staff's Second Set of Interrogatories No. 2 *Bates Nos. 00052-00061*	1, 4, 5, 6, 7	
41	Timothy Hill (4) Reginald Anderson (5) Gary P. Dean (6)	Staff Exhibit 41	DEF's response to Staff's Third Set of Interrogatories Nos. 4-6 *Bates Nos. 00062-00068*	2, 4, 5, 6, 7	

42	Kim Spence McDaniel (7-8)	Staff Exhibit 42	DEF’s response to Staff’s Fourth Set of Interrogatories Nos. 7-8 *Bates Nos. 00069-00073*	3, 4, 5, 6, 7, 8, 9	
43	N/A	Staff Exhibit 43	TECO’s response to Staff’s First Request for Production Nos. 1-2 **(No. 1 has attachments)** *Bates Nos. 00074-00077*	3, 4, 5, 6, 7, 8, 9	
44	M. Ashley Sizemore (3-13)	Staff Exhibit 44	TECO’s response to Staff's Third Set of Interrogatories Nos. 3-13 *Bates Nos. 00078-00091*	1, 4, 5, 6, 7	
45	M. Ashley Sizemore (14)	Staff Exhibit 45	TECO’s response to Staff's Fourth Set of Interrogatories No. 14 *Bates Nos. 00092-00093*	1, 4, 5, 6, 7	
46	M. Ashley Sizemore (15-17)	Staff Exhibit 46	TECO’s response to Staff's Fifth Set of Interrogatories Nos. 15-17 *Bates Nos. 00094-00099*	2, 4, 5, 6, 7	
47	M. Ashley Sizemore (18-24)	Staff Exhibit 47	TECO’s response to Staff's Sixth Set of Interrogatories Nos. 18-24 *Bates Nos. 00100-00107*	3, 4, 5, 6, 7, 8, 9	
48		Staff Exhibit 48	TECO’s response to Staff’s Seventh Set of Interrogatories No. 25 *Bates Nos. 00108-00109*	3, 4, 5, 6, 7, 8, 9	
49	N/A	Staff Exhibit 49	Letter from Malcolm Means/TECO dated 10/1/21, With Attached 2022 Cost Recovery Factors Document No: 011811-2021 *Bates Nos. 00110-00224*	3, 4, 5, 6, 7, 8, 9	

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE FINAL TRUE-UP AMOUNT FOR THE PERIOD

FORM: 42-1A

JANUARY 2020 THROUGH DECEMBER 2020

	2020
1. Over/(Under) Recovery for the Current Period (Form 42-2A, Line 5)	$19,205,214
2. Interest Provision (Form 42-2A, Line 6)	$215,878
3. Total	$19,421,091
4. Actual/Estimated Over/(Under) Recovery for the Same Period [a]	$4,556,972
5. Interest Provision	$206,813
6. Total	$4,763,785
7. Net True-Up for the period	$14,657,307

[a] Approved in Order No. PSC-2020-0433-FOF-EI issued on November 13, 2020

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE FINAL TRUE-UP AMOUNT FOR THE PERIOD

FORM: 42-2A

JANUARY 2020 THROUGH DECEMBER 2020

	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Total
1. ECRC Revenues (net of Revenue Taxes)	$11,896,518	$10,915,932	$11,468,761	$13,476,593	$13,484,729	$14,961,745	$16,605,020	$16,764,613	$16,589,736	$14,802,906	$13,882,212	$11,582,062	$166,430,827
2. True-up Provision [b]	$2,442,450	$2,442,450	$2,442,450	$2,442,450	$2,442,450	$2,442,450	$2,442,450	$2,442,450	$2,442,450	$2,442,450	$2,442,450	$2,442,450	$29,309,402
3. ECRC Revenues Applicable to Period (Lines 1 + 2)	$14,338,969	$13,358,383	$13,911,211	$15,919,043	$15,927,179	$17,404,195	$19,047,470	$19,207,063	$19,032,186	$17,245,357	$16,324,662	$14,024,512	$195,740,229
4. Jurisdictional ECRC Costs													
a. O&M Activities (Form 42-5A-2, Line 9)	$2,659,886	$3,252,500	$2,187,838	$2,533,824	$2,586,271	$1,826,076	$2,329,491	$2,503,771	$1,782,402	$2,414,464	$2,335,254	$2,161,583	$28,573,360
b. Capital Investment Projects (Form 42-7A-2, Line 8)	$12,370,558	$12,356,337	$12,349,948	$12,342,143	$12,341,323	$12,380,741	$12,323,789	$12,314,310	$12,302,372	$12,289,285	$12,273,762	$12,317,088	$147,961,656
c. Total Jurisdictional ECRC Costs	$15,030,444	$15,608,836	$14,537,786	$14,875,968	$14,927,594	$14,206,817	$14,653,280	$14,818,081	$14,084,774	$14,703,749	$14,609,016	$14,478,671	$176,535,015
5. Over/(Under) Recovery (Line 3 - Line 4c)	($691,475)	($2,250,454)	($626,575)	$1,043,075	$999,585	$3,197,378	$4,394,190	$4,388,982	$4,947,412	$2,541,608	$1,715,647	($454,159)	$19,205,214
6. Interest Provision (Form 42-3A, Line 10)	$56,297	$50,631	$53,633	$30,231	$1,783	$2,645	$3,158	$3,353	$3,576	$3,244	$3,829	$3,495	$215,878
7. Prior Periods True-Up to be (Collected)/Refunded	$29,309,402	$26,231,773	$21,589,500	$18,574,108	$17,204,964	$15,763,882	$16,521,455	$18,476,354	$20,426,240	$22,934,778	$23,037,180	$22,314,205	$29,309,402
a. Deferred True-Up (Form 42-1A, Line 7) [c]	$14,087,943	$14,087,943	$14,087,943	$14,087,943	$14,087,943	$14,087,943	$14,087,943	$14,087,943	$14,087,943	$14,087,943	$14,087,943	$14,087,943	
8. True-Up Collected /(Refunded) (See Line 2)	($2,442,450)	($2,442,450)	($2,442,450)	($2,442,450)	($2,442,450)	($2,442,450)	($2,442,450)	($2,442,450)	($2,442,450)	($2,442,450)	($2,442,450)	($2,442,450)	($29,309,402)
9. End of Period True-Up (Lines 5+6+7+7a+8)	$40,319,717	$35,677,443	$32,662,051	$31,292,907	$29,851,825	$30,609,399	$32,564,297	$34,514,183	$37,022,721	$37,125,123	$36,402,149	$33,509,035	$19,421,091
10. Adjustments to Period Total True-Up Including Interest	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11. End of Period Total Net True-Up (Lines 9+10)	$40,319,717	$35,677,443	$32,662,051	$31,292,907	$29,851,825	$30,609,399	$32,564,297	$34,514,183	$37,022,721	$37,125,123	$36,402,149	$33,509,035	$19,421,091

[b] As approved in Order No. PSC-2020-0433-FOF-EI issued on November 13, 2020
[c] From FPL's 2019 Final True-up filed on April 1,2020.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE FINAL TRUE-UP AMOUNT FOR THE PERIOD

FORM: 42-3A

JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	Total
1. Beginning True-Up Amount (Form 42-2A, Lines 7 + 7a + 10)	$43,397,345	$40,319,716	$35,677,443	$32,662,051	$31,292,907	$29,851,825	$30,609,399	$32,564,297	$34,514,183	$37,022,721	$37,125,123	$36,402,149	N/A
2. Ending True-Up Amount before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	$40,263,419	$35,626,812	$32,608,418	$31,262,676	$29,850,042	$30,606,754	$32,561,139	$34,510,829	$37,019,145	$37,121,879	$36,398,319	$33,505,539	N/A
3. Total of Beginning & Ending True-Up (Lines 1 + 2)	$83,660,764	$75,946,528	$68,285,861	$63,924,727	$61,142,949	$60,458,579	$63,170,537	$67,075,126	$71,533,328	$74,144,600	$73,523,442	$69,907,688	N/A
4. Average True-Up Amount (Line 3 x 1/2)	$41,830,382	$37,973,264	$34,142,931	$31,962,363	$30,571,475	$30,229,290	$31,585,269	$33,537,563	$35,766,664	$37,072,300	$36,761,721	$34,953,844	N/A
5. Interest Rate (First Day of Reporting Month)	1.59000%	1.64000%	1.56000%	2.21000%	0.06000%	0.08000%	0.13000%	0.11000%	0.13000%	0.11000%	0.10000%	0.15000%	N/A
6. Interest Rate (First Day of Subsequent Month)	1.64000%	1.56000%	2.21000%	0.06000%	0.08000%	0.13000%	0.11000%	0.13000%	0.11000%	0.10000%	0.15000%	0.09000%	N/A
7. Total of Beginning & Ending Interest Rates (Lines 5 + 6)	3.23000%	3.20000%	3.77000%	2.27000%	0.14000%	0.21000%	0.24000%	0.24000%	0.24000%	0.21000%	0.25000%	0.24000%	N/A
8. Average Interest Rate (Line 7 x 1/2)	1.61500%	1.60000%	1.88500%	1.13500%	0.07000%	0.10500%	0.12000%	0.12000%	0.12000%	0.10500%	0.12500%	0.12000%	N/A
9. Monthly Average Interest Rate (Line 8 x 1/12)	0.13458%	0.13333%	0.15708%	0.09458%	0.00583%	0.00875%	0.01000%	0.01000%	0.01000%	0.00875%	0.01042%	0.01000%	N/A
10. Interest Provision for the Month (Line 4 x Line 9)	$56,297	$50,631	$53,633	$30,231	$1,783	$2,645	$3,159	$3,354	$3,577	$3,244	$3,829	$3,495	$215,878

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE FINAL TRUE-UP AMOUNT FOR THE PERIOD

FORM: 42-4A-1

JANUARY 2020 THROUGH DECEMBER 2020
VARIANCE REPORT OF O&M ACTIVITES

(1)	(2)	(3)	(4)	(5)
O&M Projects	ECRC - 2020 Final True-Up (a)	ECRC - 2020 Actual/Estimated (b)	Dif. ECRC - 2020 Actual/Estimated (c)	% Dif. ECRC - 2020 Actual/Estimated (d)
1 - Air Operating Permit Fees	$224,690	$157,384	$67,306	42.8%
3a - Continuous Emission Monitoring Systems	$300,873	$384,047	($83,174)	(21.7%)
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	$236,354	$511,197	($274,843)	(53.8%)
8a - Oil Spill Clean-up/Response Equipment	$273,692	$360,809	($87,118)	(24.1%)
NA-Amortization of Gains on Sales of Emissions Allowances	($141)	($73)	($68)	92.4%
14 - NPDES Permit Fees	$69,200	$69,200	$0	0.0%
19a - Substation Pollutant Discharge Prevention & Removal - Distribution	$3,846,300	$3,556,993	$289,307	8.1%
19b - Substation Pollutant Discharge Prevention & Removal - Transmission	$1,285,445	$1,285,675	($230)	(0.0%)
21 - St. Lucie Turtle Nets	$326,110	$299,282	$26,828	9.0%
22 - Pipeline Integrity Management	$65,345	$327,500	($262,155)	(80.0%)
23 - SPCC - Spill Prevention, Control & Countermeasures	$937,644	$785,841	$151,803	19.3%
24 - Manatee Reburn	$26,086	$23,672	$2,414	10.2%
27 - Lowest Quality Water Source	$107,889	$107,675	$214	0.2%
28 - CWA 316(b) Phase II Rule	$896,307	$1,068,913	($172,606)	(16.1%)
29 - SCR Consumables	$526,381	$637,223	($110,842)	(17.4%)
31 - Clean Air Interstate Rule (CAIR) Compliance	$3,872,787	$3,833,259	$39,527	1.0%
33 - MATS Project	$1,441,750	$1,888,540	($446,790)	(23.7%)
35 - Martin Plant Drinking Water System Compliance	$8,629	$10,492	($1,863)	(17.8%)
37 - DeSoto Next Generation Solar Energy Center	$557,431	$670,971	($113,540)	(16.9%)
38 - Space Coast Next Generation Solar Energy Center	$198,383	$268,593	($70,210)	(26.1%)
39 - Martin Next Generation Solar Energy Center	$4,861,127	$4,747,474	$113,652	2.4%
41 - Manatee Temporary Heating System	$120,038	$152,070	($32,032)	(21.1%)
42 - Turkey Point Cooling Canal Monitoring Plan	$9,321,841	$19,694,511	($10,372,669)	(52.7%)
45 - 800 MW Unit ESP	$35,744	$154,969	($119,225)	(76.9%)
47 - NPDES Permit Renewal Requirements	$205,440	$93,797	$111,643	119.0%
48 - Industrial Boiler MACT	$1,804	$32,668	($30,865)	(94.5%)
50 - Steam Electric Effluent Guidelines Revised Rules	$5,258	$4,608	$650	14.1%
51 - Gopher Tortoise Relocations	$31,388	$28,732	$2,656	9.2%
123-Protected Species Project	$38,000	$34,000	$4,000	11.8%
Total	29,821,795	41,190,022	(11,368,227)	(27.60%)

(a) The 12-Month Totals on Form 42-5A

(b) The approved amount in accordance with FPSC Order No. PSC-2020-0433-FOF-EI

(c) Column (2) - Column (3)

(d) Column (4) / Column (3)

FORM: 42-4A-2

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE FINAL TRUE-UP AMOUNT FOR THE PERIOD

JANUARY 2020 THROUGH DECEMBER 2020
VARIANCE REPORT OF O&M ACTIVITES

(1)	(2)	(3)	(4)	(5)
	ECRC - 2020 Final True-Up (a)	ECRC - 2020 Actual/Estimated (b)	Dif. ECRC - 2020 Actual/Estimated (c)	% Dif. ECRC - 2020 Actual/Estimated (d)
2. Total of O&M Activities	$29,821,795	$41,190,022	($11,368,227)	(27.60%)
3. Recoverable Costs Allocated to Energy	$16,143,742	$27,286,411	($11,142,670)	(40.84%)
4a. Recoverable Costs Allocated to CP Demand	$9,831,881	$10,346,618	($514,737)	(4.97%)
4b. Recoverable Costs Allocated to GCP Demand	$3,846,172	$3,556,993	$289,179	8.13%
5. Jurisdictional Energy Recoverable Costs	$15,458,461	$26,137,392	($10,678,931)	(40.86%)
6a. Jurisdictional CP Demand Recoverable Costs	$9,268,726	$9,750,876	($482,150)	(4.94%)
6b. Jurisdictional GCP Demand Recoverable Costs	$3,846,172	$3,556,993	$289,179	8.13%
7. Total Jurisdictional Recoverable Costs for O&M Activities	$28,573,360	$39,445,262	($10,871,902)	(27.56%)

[a] The 12-Month Totals on Form 42-5A

[b] The approved amount in accordance with FPSC Order No. PSC-2020-0433-FOF-EI

[c] Column (2) - Column (3)

[d] Column (4) / Column (3)

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE FINAL TRUE-UP AMOUNT FOR THE PERIOD

FORM: 42-5A

JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
O&M Projects	Strata	Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	2020
1 - Air Operating Permit Fees	Base	$11,135	$11,135	$11,135	$11,135	$11,135	$11,135	$11,135	$11,135	$11,135	$11,135	$11,135	$11,135	$133,620
1 - Air Operating Permit Fees	Intermediate	$1,800	$1,800	$2,158	$4,645	$4,645	$4,645	$9,713	$9,713	$9,713	$9,713	$9,713	$9,713	$77,971
1 - Air Operating Permit Fees	Peaking	$263	$263	($28,063)	$263	$263	$263	$6,641	$6,641	$6,641	$6,641	$6,641	$6,641	$13,100
3a - Continuous Emission Monitoring Systems	Intermediate	$78,268	$10,799	$16,018	$34,346	$23,563	$15,576	($9,310)	$19,461	$2,942	$7,810	$13,582	$38,148	$251,203
3a - Continuous Emission Monitoring Systems	Peaking	$34,861	$1,197	($263)	$325	$191	$0	$292	$125	$228	$8,246	$3,838	$631	$49,671
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Base	$0	$0	$5,846	$0	$0	$0	$0	$8,025	$0	$0	$0	$0	$13,871
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Intermediate	$1,185	$3,027	$7,152	$187	$2,685	$0	$0	$0	$0	$0	$0	$0	$14,236
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Peaking	$1,914	$3,846	$0	$1,403	$5,043	$2,750	$0	$101	$0	$8,378	$194,023	($9,211)	$208,247
8a - Oil Spill Clean-up/Response Equipment	Base	$0	$0	$0	$55	($55)	$0	$0	$0	$0	$0	$0	$0	($1)
8a - Oil Spill Clean-up/Response Equipment	Intermediate	($2,610)	$862	$1,597	$784	$238	$2,737	$0	$5,314	$4,192	$4,015	$3,849	$9,128	$30,107
8a - Oil Spill Clean-up/Response Equipment	Peaking	($21,118)	$6,974	$12,920	$6,632	$1,637	$22,148	$0	$42,995	$33,916	$32,482	$31,142	$73,858	$243,586
14 - NPDES Permit Fees	Base	$11,500	$2,585	$0	$0	($2,585)	$0	$0	$0	$0	$0	$0	$0	$11,500
14 - NPDES Permit Fees	Intermediate	$28,260	$0	$0	$0	$0	$0	$0	$7,500	$0	($7,500)	$0	$0	$28,260
14 - NPDES Permit Fees	Peaking	$29,440	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$29,440
19a - Substation Pollutant Discharge Prevention & Removal - Distribution	Distribution	$260,603	$484,062	$496,230	$674,771	$350,779	$239,671	$196,729	$171,615	$63,718	$361,284	$139,656	$407,055	$3,846,172
19a - Substation Pollutant Discharge Prevention & Removal - Distribution	Transmission	$0	$0	$0	$0	$0	$128	$0	$0	$0	$0	$0	$0	$128
19b - Substation Pollutant Discharge Prevention & Removal - Transmission	Transmission	$13,313	$72,809	$77,617	$221,174	$397,476	$65,820	$49,159	$117,647	$19,194	$56,578	$131,125	$63,533	$1,285,445
21 - St. Lucie Turtle Nets	Base	($12,785)	$15,475	$6,510	$48,406	$26,775	$18,578	$92,766	$22,155	$18,848	$33,555	$23,540	$32,286	$326,110
NA-Amortization of Gains on Sales of Emissions Allowances	Base	($1)	($1)	($1)	$0	$0	($3)	$0	$0	($3)	$0	$0	($3)	($13)
NA-Amortization of Gains on Sales of Emissions Allowances	Intermediate	($4)	($4)	($4)	$0	$0	($19)	$0	$0	($43)	$0	$0	($12)	($87)
NA-Amortization of Gains on Sales of Emissions Allowances	Peaking	($2)	($2)	($2)	$0	$0	($6)	$0	$0	($22)	$0	$0	($6)	($41)
22 - Pipeline Integrity Management	Intermediate	$0	$12	$0	$0	$0	$0	$0	$0	$0	$27,060	$41	$0	$27,114
22 - Pipeline Integrity Management	Peaking	$0	$18	$0	$0	$0	$0	$0	$0	$0	$38,155	$59	$0	$38,231
23 - SPCC - Spill Prevention, Control & Countermeasures	Distribution	$51,630	$61,863	$68,510	$73,741	$41,884	$93,947	$54,329	$44,900	$19,975	$148,917	$56,183	$44,761	$760,639
23 - SPCC - Spill Prevention, Control & Countermeasures	Intermediate	$0	$1,408	$4,192	$1,965	($5,156)	$7,094	$5,825	$2,271	$924	$3,770	$0	$3,017	$25,309
23 - SPCC - Spill Prevention, Control & Countermeasures	Peaking	$0	$680	$24	$0	$164	$1,761	$1,430	$883	$0	$450	$0	$165	$5,557
23 - SPCC - Spill Prevention, Control & Countermeasures	Transmission	$9,165	$27,525	$8,049	$11,735	$9,896	$11,959	$8,659	$9,463	$5,136	$16,189	$17,533	$10,831	$146,139
24 - Manatee Reburn	Peaking	$3,165	$15,302	$96	$4,887	$222	$91	$0	$0	$0	$0	$2,323	$0	$26,086
27 - Lowest Quality Water Source	Intermediate	$11,398	$8,826	$9,007	$8,042	$7,957	$8,526	$9,342	$9,736	$8,486	$8,751	$8,826	$8,993	$107,889
28 - CWA 316(b) Phase II Rule	Base	$6,484	$5,648	$6,547	$19,138	$4,956	$30,221	$10,876	$12,602	$16,277	$14,917	$42,473	$34,830	$204,968
28 - CWA 316(b) Phase II Rule	Intermediate	$66,524	$62,577	$94,433	$57,257	$91,533	$68,452	$52,562	$47,417	$78,625	$31,667	$26,909	$9,204	$687,160
28 - CWA 316(b) Phase II Rule	Peaking	$376	($6,073)	$692	$721	$5,868	$472	$344	$336	$342	$429	$304	$369	$4,179
29 - SCR Consumables	Intermediate	$153,282	$5,143	$15,013	$15,180	$20,556	$29,448	$34,991	$46,678	$39,745	$9,018	$116,319	$41,009	$526,381
31 - Clean Air Interstate Rule (CAIR) Compliance	Base	$276,381	$295,376	$317,954	$439,096	$427,619	$391,699	$258,877	$311,738	$269,152	$332,622	$200,827	$221,134	$3,742,476
31 - Clean Air Interstate Rule (CAIR) Compliance	Peaking	$9,444	$9,577	$14,040	$16,046	$10,050	$10,012	$9,913	$10,478	$10,492	$10,601	$10,168	$9,491	$130,311
33 - MATS Project	Base	$278,093	$36,242	$61,096	$56,985	$119,863	$2,153	$209,878	$174,737	$162,435	$91,081	$69,348	$179,839	$1,441,750
35 - Martin Plant Drinking Water System Compliance	Peaking	$0	$2,673	$2,607	$2,713	$0	$37	$0	$0	$0	$600	$0	$0	$8,629
37 - DeSoto Next Generation Solar Energy Center	Solar	$42,764	$39,408	$29,698	$48,240	($5,725)	$69,647	$93,696	$54,745	$38,231	$63,641	$42,054	$41,033	$557,431
38 - Space Coast Next Generation Solar Energy Center	Solar	$17,828	$21,617	$16,657	$37,522	$9,725	$22,952	$16,667	$8,349	$5,389	$9,632	$10,174	$21,871	$198,383
39 - Martin Next Generation Solar Energy Center	Intermediate	$432,285	$1,166,061	$76,194	$328,349	$306,532	$337,067	$360,295	$348,082	$307,672	$287,430	$585,006	$326,154	$4,861,127
41 - Manatee Temporary Heating System	Intermediate	$20,365	($6,821)	$7,301	($174)	$45,264	$3,740	$12,289	$0	$9,023	$25,102	$0	$3,949	$120,038
42 - Turkey Point Cooling Canal Monitoring Plan	Base	$925,279	$1,002,025	$906,034	$502,844	$772,915	$424,065	$933,675	$1,080,672	$714,587	$832,706	$626,035	$603,710	$9,324,545
42 - Turkey Point Cooling Canal Monitoring Plan	Intermediate	$0	$2,935	$0	$3,473	$4,941	$6,535	($21,517)	$0	$929	$0	$0	$0	($2,704)
45 - 800 MW Unit ESP	Peaking	$360	$32,144	$0	$107	$50	$324	$0	$455	$966	$0	$1,338	$0	$35,744
47 - NPDES Permit Renewal Requirements	Base	$35,262	($2,778)	$12,587	($997)	$13,499	$0	$5,228	$0	$0	$5,969	$68,135	$36,067	$172,972
47 - NPDES Permit Renewal Requirements	Intermediate	$0	$0	$7,450	$2,513	$8,512	$0	$0	$0	$7,401	$2,688	$0	$3,904	$32,468
48 - Industrial Boiler MACT	Base	$0	$45	$0	$0	$27	$0	$0	$0	$0	$0	$0	$217	$289
48 - Industrial Boiler MACT	Peaking	$0	$235	$0	$0	$141	$0	$0	$0	$0	$0	$0	$1,139	$1,515
50 - Steam Electric Effluent Guidelines Revised Rules	Base	$229	$1,695	$238	$19	$2,033	$0	$104	$0	$0	$0	$0	$0	$4,319
50 - Steam Electric Effluent Guidelines Revised Rules	Peaking	$393	$0	$0	$0	$0	$0	$546	$0	$0	$0	$0	$0	$939
51 - Gopher Tortoise Relocations	Peaking	$0	$0	$0	$0	$0	$0	$15,883	$0	$0	$15,505	$0	$0	$31,388
123-Protected Species Project	Intermediate	$0	$0	$0	$0	$0	$0	$0	$34,000	$0	$0	$0	$4,000	$38,000
	Total	$2,776,728	$3,398,190	$2,267,268	$2,633,528	$2,715,114	$1,904,104	$2,431,016	$2,619,970	$1,865,767	$2,509,233	$2,452,298	$2,248,580	$29,821,795

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE FINAL TRUE-UP AMOUNT FOR THE PERIOD

JANUARY 2020 THROUGH DECEMBER 2020
O&M ACTIVITIES

O&M Project	Strata	Monthly Data	Jurisdictionalization		Method of Classification		
		Twelve Month Total	Jurisdictional Factor	Juris Twelve Month Amount	Energy	CP Demand	GCP Demand
1 - Air Operating Permit Fees	Base	$133,620	95.8799%	$128,115	$128,115	$0	$0
1 - Air Operating Permit Fees	Intermediate	$77,971	94.2430%	$73,482	$73,482	$0	$0
1 - Air Operating Permit Fees	Peaking	$13,100	95.1325%	$12,462	$12,462	$0	$0
3a - Continuous Emission Monitoring Systems	Intermediate	$251,203	94.2430%	$236,741	$236,741	$0	$0
3a - Continuous Emission Monitoring Systems	Peaking	$49,671	95.1325%	$47,253	$47,253	$0	$0
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Base	$13,871	95.7922%	$13,287	$0	$13,287	$0
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Intermediate	$14,236	94.1569%	$13,404	$0	$13,404	$0
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Peaking	$208,247	95.0455%	$197,929	$0	$197,929	$0
8a - Oil Spill Clean-up/Response Equipment	Base	($1)	95.8799%	($1)	($1)	$0	$0
8a - Oil Spill Clean-up/Response Equipment	Intermediate	$30,107	94.2430%	$28,373	$28,373	$0	$0
8a - Oil Spill Clean-up/Response Equipment	Peaking	$243,586	95.1325%	$231,729	$231,729	$0	$0
14 - NPDES Permit Fees	Base	$11,500	95.7922%	$11,016	$0	$11,016	$0
14 - NPDES Permit Fees	Intermediate	$28,260	94.1569%	$26,609	$0	$26,609	$0
14 - NPDES Permit Fees	Peaking	$29,440	95.0455%	$27,981	$0	$27,981	$0
19a - Substation Pollutant Discharge Prevention & Removal - Distribution	Distribution	$3,846,172	100.0000%	$3,846,172	$0	$0	$3,846,172
19a - Substation Pollutant Discharge Prevention & Removal - Distribution	Transmission	$128	89.9387%	$115	$0	$115	$0
19b - Substation Pollutant Discharge Prevention & Removal - Transmission	Transmission	$1,285,445	89.9387%	$1,156,113	$0	$1,156,113	$0
21 - St. Lucie Turtle Nets	Base	$326,110	95.7922%	$312,388	$0	$312,388	$0
NA-Amortization of Gains on Sales of Emissions Allowances	Base	($13)	95.8799%	($13)	($13)	$0	$0
NA-Amortization of Gains on Sales of Emissions Allowances	Intermediate	($87)	94.2430%	($82)	($82)	$0	$0
NA-Amortization of Gains on Sales of Emissions Allowances	Peaking	($41)	95.1325%	($39)	($39)	$0	$0
22 - Pipeline Integrity Management	Intermediate	$27,114	94.1569%	$25,529	$0	$25,529	$0
22 - Pipeline Integrity Management	Peaking	$38,231	95.0455%	$36,337	$0	$36,337	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Intermediate	$25,309	94.1569%	$23,830	$0	$23,830	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Peaking	$5,557	95.0455%	$5,282	$0	$5,282	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Distribution	$760,639	100.0000%	$760,639	$0	$760,639	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Transmission	$146,139	89.9387%	$131,435	$0	$131,435	$0
24 - Manatee Reburn	Peaking	$26,086	95.1325%	$24,816	$24,816	$0	$0
27 - Lowest Quality Water Source	Intermediate	$107,889	94.1569%	$101,585	$0	$101,585	$0
28 - CWA 316(b) Phase II Rule	Base	$204,968	95.7922%	$196,343	$0	$196,343	$0
28 - CWA 316(b) Phase II Rule	Intermediate	$687,160	94.1569%	$647,008	$0	$647,008	$0
28 - CWA 316(b) Phase II Rule	Peaking	$4,179	95.0455%	$3,972	$0	$3,972	$0
29 - SCR Consumables	Intermediate	$526,381	94.2430%	$496,078	$496,078	$0	$0
31 - Clean Air Interstate Rule (CAIR) Compliance	Base	$3,742,476	95.8799%	$3,588,282	$3,588,282	$0	$0
31 - Clean Air Interstate Rule (CAIR) Compliance	Peaking	$130,311	95.1325%	$123,968	$123,968	$0	$0
33 - MATS Project	Base	$1,441,750	95.8799%	$1,382,349	$1,382,349	$0	$0
35 - Martin Plant Drinking Water System Compliance	Peaking	$8,629	95.0455%	$8,202	$0	$8,202	$0
37 - DeSoto Next Generation Solar Energy Center	Solar	$557,431	95.7922%	$533,976	$0	$533,976	$0
38 - Space Coast Next Generation Solar Energy Center	Solar	$198,383	95.7922%	$190,035	$0	$190,035	$0
39 - Martin Next Generation Solar Energy Center	Intermediate	$4,861,127	94.1569%	$4,577,086	$0	$4,577,086	$0
41 - Manatee Temporary Heating System	Intermediate	$120,038	94.2430%	$113,127	$113,127	$0	$0
42 - Turkey Point Cooling Canal Monitoring Plan	Base	$9,324,545	95.8799%	$8,940,364	$8,940,364	$0	$0
42 - Turkey Point Cooling Canal Monitoring Plan	Intermediate	($2,704)	94.2430%	($2,548)	($2,548)	$0	$0
45 - 800 MW Unit ESP	Peaking	$35,744	95.1325%	$34,004	$34,004	$0	$0
47 - NPDES Permit Renewal Requirements	Base	$172,972	95.7922%	$165,694	$0	$165,694	$0
47 - NPDES Permit Renewal Requirements	Intermediate	$32,468	94.1569%	$30,571	$0	$30,571	$0
48 - Industrial Boiler MACT	Base	$289	95.7922%	$276	$0	$276	$0
48 - Industrial Boiler MACT	Peaking	$1,515	95.0455%	$1,440	$0	$1,440	$0
50 - Steam Electric Effluent Guidelines Revised Rules	Base	$4,319	95.7922%	$4,137	$0	$4,137	$0
50 - Steam Electric Effluent Guidelines Revised Rules	Peaking	$939	95.0455%	$893	$0	$893	$0
51 - Gopher Tortoise Relocations	Peaking	$31,388	95.0455%	$29,833	$0	$29,833	$0
123-Protected Species Project	Intermediate	$38,000	94.1569%	$35,780	$0	$35,780	$0
	Total	$29,821,795		$28,573,360	$15,458,461	$9,268,726	$3,846,172

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE FINAL TRUE-UP AMOUNT FOR THE PERIOD

FORM: 42-5A

JANUARY 2020 THROUGH DECEMBER 2020
O&M ACTIVITIES

	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	2020
2. Total of O&M Activities	$2,776,728	$3,398,190	$2,267,268	$2,633,528	$2,715,114	$1,904,104	$2,431,016	$2,619,970	$1,865,767	$2,509,233	$2,452,298	$2,248,580	$29,821,795
3. Recoverable Costs Allocated to Energy - Base	$1,490,886	$1,344,777	$1,296,218	$1,010,115	$1,331,477	$829,049	$1,413,565	$1,578,283	$1,157,305	$1,267,543	$907,345	$1,015,815	$14,642,377
Recoverable Costs Allocated to Energy - Intermediate	$251,101	$14,714	$42,082	$58,254	$99,207	$62,664	$26,165	$81,166	$66,501	$55,657	$143,463	$101,936	$1,002,909
Recoverable Costs Allocated to Energy - Peaking	$26,973	$65,455	($1,273)	$28,260	$12,413	$32,833	$16,846	$60,695	$52,221	$57,969	$55,450	$90,614	$498,456
4. Recoverable Costs Jurisdictionalized on 12 CP Demand - Transmission	$22,477	$100,335	$85,667	$232,909	$407,372	$77,906	$57,818	$127,110	$24,329	$72,767	$148,658	$74,363	$1,431,712
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Base	$40,690	$22,671	$31,728	$66,567	$44,705	$48,799	$108,974	$42,783	$35,125	$54,440	$134,148	$103,399	$734,029
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Interm.	$539,653	$1,241,911	$198,427	$398,313	$412,061	$421,139	$428,025	$449,006	$403,108	$353,865	$620,782	$355,271	$5,821,561
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Peaking	$32,123	$1,378	$3,323	$4,837	$11,216	$5,020	$18,202	$1,320	$342	$63,518	$194,386	($7,537)	$328,126
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Solar	$60,592	$61,024	$46,355	$85,762	$4,000	$92,599	$110,363	$63,094	$43,620	$73,274	$52,227	$62,904	$755,814
Recoverable Costs Jurisdictionalized on 12 CP Demand - Distribution	$51,630	$61,863	$68,510	$73,741	$41,884	$93,947	$54,329	$44,900	$19,975	$148,917	$56,183	$44,761	$760,639
5. Recoverable Costs Jurisdictionalized on GCP Demand - Distribution	$260,603	$484,062	$496,230	$674,771	$350,779	$239,671	$196,729	$171,615	$63,718	$361,284	$139,656	$407,055	$3,846,172
6. Retail Production Energy Jurisdictional Factor - Base	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	
Retail Production Energy Jurisdictional Factor - Intermediate	94.24302%	94.24302%	94.24302%	94.24302%	94.24302%	94.24302%	94.24302%	94.24302%	94.24302%	94.24302%	94.24302%	94.24302%	
Retail Production Energy Jurisdictional Factor - Peaking	95.13247%	95.13247%	95.13247%	95.13247%	95.13247%	95.13247%	95.13247%	95.13247%	95.13247%	95.13247%	95.13247%	95.13247%	
Retail Production Energy Jurisdictional Factor - Solar	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	
7. Retail Distribution Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	
Retail Transmission Demand Jurisdictional Factor	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	
Retail Production Demand Jurisdictional Factor - Base	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	
Retail Production Demand Jurisdictional Factor - Intermediate	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	
Retail Production Demand Jurisdictional Factor - Peaking	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	
Retail Production Demand Jurisdictional Factor - Solar	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	
8. Jurisdictional Recoverable Costs- Transmission	$20,216	$90,240	$77,048	$209,475	$366,385	$70,068	$52,001	$114,321	$21,882	$65,446	$133,701	$66,881	$1,287,663
Jurisdictional Recoverable Costs - Production - Base	$1,468,438	$1,311,088	$1,273,205	$1,032,263	$1,319,443	$841,636	$1,459,713	$1,554,238	$1,143,270	$1,267,468	$998,465	$1,073,010	$14,742,239
Jurisdictional Recoverable Costs - Production - Intermediate	$744,766	$1,183,212	$226,493	$429,940	$481,480	$455,588	$427,673	$499,263	$442,227	$385,641	$719,713	$430,579	$6,426,573
Jurisdictional Recoverable Costs - Production - Peaking	$56,191	$63,579	$1,948	$31,482	$22,469	$36,006	$33,327	$58,995	$50,004	$115,518	$237,506	$79,039	$786,063
Jurisdictional Recoverable Costs - Production - Solar	$58,042	$58,457	$44,405	$82,154	$3,831	$89,161	$105,719	$60,439	$41,327	$70,191	$50,030	$60,257	$724,011
Jurisdictional Recoverable Costs - Distribution	$312,233	$545,925	$564,740	$748,511	$392,663	$333,618	$251,058	$216,515	$83,693	$510,200	$195,840	$451,816	$4,606,811
9. Total Jurisdictional Recoverable Costs for O&M Activities	$2,659,886	$3,252,499	$2,187,838	$2,533,824	$2,586,271	$1,826,076	$2,329,490	$2,503,771	$1,782,402	$2,414,464	$2,335,253	$2,161,583	$28,573,360

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE FINAL TRUE-UP AMOUNT FOR THE PERIOD

FORM: 42-6A

JANUARY 2020 THROUGH DECEMBER 2020
VARIANCE REPORT OF CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

(1)	(2)	(3)	(4)	(5)
Capital Projects	ECRC - 2020 Final True-Up	ECRC - 2020 Actual/Estimated Filing	Dif. ECRC - 2020 Actual/Estimated (c)	% Dif. ECRC - 2020 Actual/Estimated (d)
02 - Low NOX Burner Technology	$57,069	$57,069	$0	0.00%
03 - Continuous Emission Monitoring Systems	$467,882	$467,855	$27	0.01%
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	$1,643,393	$1,660,195	($16,801)	-1.01%
07 - Relocate Turbine Lube Oil Underground Piping to Above Ground	$1,535	$1,535	$0	0.00%
08 - Oil Spill Clean-up/Response Equipment	$195,425	$195,267	$157	0.08%
10 - Relocate Storm Water Runoff	$6,215	$6,215	$0	0.00%
NA-Amortization of Gains on Sales of Emissions Allowances	($17)	($17)	$0	-2.32%
12 - Scherer Discharge Pipeline	$33,749	$33,749	$0	0.00%
20 - Wastewater Discharge Elimination & Reuse	$42,408	$42,408	$0	0.00%
21 - St. Lucie Turtle Nets	$734,751	$734,751	$0	0.00%
22 - Pipeline Integrity Management	$263,403	$263,403	$0	0.00%
23 - SPCC - Spill Prevention, Control & Countermeasures	$2,203,072	$2,221,898	($18,826)	-0.85%
24 - Manatee Reburn	$2,979,301	$2,979,301	$0	0.00%
26 - UST Remove/Replacement	$6,651	$6,651	$0	0.00%
28 - CWA 316(b) Phase II Rule	$77,810	$77,810	$0	0.00%
31 - Clean Air Interstate Rule (CAIR) Compliance	$45,141,533	$45,144,078	($2,545)	-0.01%
33 - MATS Project	$9,423,322	$9,423,322	$0	0.00%
34 - St Lucie Cooling Water System Inspection & Maintenance	$354,914	$354,911	$2	0.00%
35 - Martin Plant Drinking Water System Compliance	$18,962	$20,188	($1,225)	-6.07%
36 - Low-Level Radioactive Waste Storage	$1,653,138	$1,653,138	$0	0.00%
37 - DeSoto Next Generation Solar Energy Center	$11,943,610	$11,943,760	($150)	0.00%
38 - Space Coast Next Generation Solar Energy Center	$5,561,299	$5,561,296	$3	0.00%
39 - Martin Next Generation Solar Energy Center	$34,081,894	$34,080,447	$1,447	0.00%
41 - Manatee Temporary Heating System	$3,338,561	$3,338,462	$100	0.00%
42 - Turkey Point Cooling Canal Monitoring Plan	$6,111,236	$6,058,054	$53,182	0.88%
44 - Martin Plant Barley Barber Swamp Iron Mitigation	$14,606	$14,606	$0	0.00%
45 - 800 MW Unit ESP	$18,821,762	$18,821,748	$14	0.00%
47 - NPDES Permit Renewal Requirements	$43,368	$53,039	($9,671)	-18.23%
50 - Steam Electric Effluent Guidelines Revised Rules	$100,275	$99,788	$487	0.49%
54 - Coal Combustion Residuals	$10,067,637	$9,951,398	$116,239	1.17%
123-The Protected Species Project	$10	$0	$10	0.00%
Total	$155,388,774	$155,266,324	$122,450	0.08%

[a] The 12-Month Totals on Form 42-5A
[b] The approved amount in accordance with FPSC Order No. PSC-2020-0433-FOF-EI
[c] Column (2) - Column (3)
[d] Column (4) / Column (3)

FORM: 42-6A

RECOVERY CLAUSE

CALCULATION OF THE FINAL TRUE-UP AMOUNT FOR THE PERIOD

JANUARY 2020 THROUGH DECEMBER 2020

VARIANCE REPORT OF CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

(1)	(2)	(3)	(4)	(5)
	ECRC - 2020 Final True-Up (a)	ECRC - 2020 Actual/Estimated (b)	Dif. ECRC - 2020 Actual/Estimated (c)	% Dif. ECRC - 2020 Actual/Estimated (d)
2. Total Investment Projects - Recoverable Costs	$155,388,774	$155,266,324	($122,450)	(0.08%)
3. Recoverable Costs Allocated to Energy	$3,504,235	$3,504,208	($27)	(0.00%)
4. Recoverable Costs Allocated to Demand	$151,884,539	$151,762,116	($122,423)	(0.08%)
5. Jurisdictional Energy Recoverable Costs	$13,076,503	$13,066,647	($9,856)	(0.08%)
8. Jurisdictional Demand Recoverable Costs	$134,885,152	$134,776,648	($108,504)	(0.08%)
9. Total Jurisdictional Recoverable Costs for Investment Projects	$147,961,655	$147,843,295	($118,360)	(0.08%)

[a] The 12-Month Totals on Form 42-7A

[b] The approved amount in accordance with FPSC Order No. PSC-2020-0433-FOF-EI

[c] Column (2) - Column (3)

[d] Column (4) / Column (3)

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE FINAL TRUE-UP AMOUNT FOR THE PERIOD

FORM: 42-7A

JANUARY 2020 THROUGH DECEMBER 2020
CAPITAL INVESTMENT PROJECTS-RECOVERABLE COSTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Capital Investment Projects [a]	Strata	Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	Twelve Month Amount
02 - Low NOX Burner Technology	Peaking	$4,876	$4,855	$4,834	$4,813	$4,792	$4,771	$4,740	$4,719	$4,698	$4,678	$4,657	$4,636	$57,069
03 - Continuous Emission Monitoring Systems	Base	$2,350	$2,342	$2,334	$2,326	$2,318	$2,310	$2,294	$2,286	$2,278	$2,271	$2,263	$2,255	$27,625
03 - Continuous Emission Monitoring Systems	Intermediate	$23,271	$23,203	$23,134	$23,065	$22,997	$22,930	$22,777	$22,710	$22,643	$22,576	$22,508	$22,441	$274,257
03 - Continuous Emission Monitoring Systems	Peaking	$14,089	$14,047	$14,005	$13,963	$13,921	$13,879	$13,787	$13,745	$13,704	$13,662	$13,620	$13,579	$166,000
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Base	$150	$150	$150	$150	$150	$150	$149	$149	$149	$149	$149	$149	$1,797
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	General	$58,947	$58,908	$58,869	$58,822	$58,775	$58,729	$58,339	$58,290	$58,242	$58,194	$58,145	$58,099	$702,358
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Intermediate	$19,065	$19,004	$18,944	$18,883	$18,823	$18,762	$18,638	$18,578	$18,518	$18,378	$18,239	$18,180	$224,012
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Peaking	$60,970	$60,741	$60,511	$60,282	$60,053	$59,824	$59,427	$59,199	$58,971	$58,684	$58,396	$58,169	$715,226
07 - Relocate Turbine Lube Oil Underground Piping to Above Ground	Base	$133	$132	$131	$130	$129	$128	$128	$127	$126	$125	$124	$123	$1,535
08 - Oil Spill Clean-up/Response Equipment	Distribution	$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$265
08 - Oil Spill Clean-up/Response Equipment	General	$28	$28	$28	$28	$28	$28	$27	$27	$27	$27	$27	$27	$330
08 - Oil Spill Clean-up/Response Equipment	Intermediate	$9,426	$10,347	$10,334	$10,308	$10,292	$10,422	$10,543	$10,566	$10,552	$10,571	$10,745	$11,499	$125,605
08 - Oil Spill Clean-up/Response Equipment	Peaking	$5,975	$5,866	$5,852	$5,829	$5,806	$5,784	$5,745	$5,723	$5,700	$5,677	$5,655	$5,612	$69,225
10 - Relocate Storm Water Runoff	Base	$527	$526	$524	$523	$521	$520	$516	$515	$513	$512	$510	$509	$6,215
NA-Amortization of Gains on Sales of Emissions Allowances	Base	($2)	($2)	($1)	($1)	($1)	($2)	($2)	($2)	($1)	($1)	($1)	($1)	($17)
12 - Scherer Discharge Pipeline	Base	$2,864	$2,856	$2,847	$2,839	$2,830	$2,822	$2,803	$2,795	$2,786	$2,778	$2,769	$2,761	$33,749
20 - Wastewater Discharge Elimination & Reuse	Peaking	$3,546	$3,546	$3,546	$3,546	$3,546	$3,546	$3,522	$3,522	$3,522	$3,522	$3,522	$3,522	$42,408
21 - St. Lucie Turtle Nets	Base	$61,864	$61,778	$61,692	$61,605	$61,519	$61,432	$61,025	$60,939	$60,853	$60,767	$60,681	$60,595	$734,751
22 - Pipeline Integrity Management	Intermediate	$11,911	$11,888	$11,866	$11,843	$11,821	$11,798	$11,720	$11,697	$11,675	$11,653	$11,630	$11,608	$141,109
22 - Pipeline Integrity Management	Peaking	$10,324	$10,304	$10,285	$10,265	$10,245	$10,225	$10,157	$10,137	$10,118	$10,098	$10,078	$10,058	$122,293
23 - SPCC - Spill Prevention, Control & Countermeasures	Base	$28,795	$28,713	$28,631	$28,549	$28,467	$28,385	$28,197	$28,116	$28,034	$27,953	$27,871	$27,790	$339,502
23 - SPCC - Spill Prevention, Control & Countermeasures	Distribution	$22,279	$22,245	$22,212	$22,179	$22,161	$22,142	$21,995	$21,963	$21,930	$22,062	$22,238	$22,248	$265,654
23 - SPCC - Spill Prevention, Control & Countermeasures	General	$910	$909	$908	$907	$905	$904	$898	$897	$896	$895	$893	$892	$10,814
23 - SPCC - Spill Prevention, Control & Countermeasures	Intermediate	$56,442	$56,637	$56,829	$56,675	$56,520	$56,509	$56,281	$56,134	$56,132	$56,107	$56,071	$56,090	$676,427
23 - SPCC - Spill Prevention, Control & Countermeasures	Peaking	$45,833	$45,859	$45,712	$45,565	$45,400	$45,169	$44,807	$44,649	$44,599	$44,518	$44,429	$44,396	$540,937
23 - SPCC - Spill Prevention, Control & Countermeasures	Transmission	$31,134	$31,088	$31,047	$31,002	$30,958	$30,914	$30,710	$30,665	$30,621	$30,577	$30,533	$30,489	$369,738
24 - Manatee Reburn	Peaking	$253,352	$252,500	$251,649	$250,797	$249,946	$249,094	$247,442	$246,596	$245,750	$244,904	$244,058	$243,212	$2,979,301
26 - UST Remove/Replacement	General	$561	$560	$559	$558	$557	$556	$552	$551	$550	$550	$549	$548	$6,651
28 - CWA 316(b) Phase II Rule	Intermediate	$6,563	$6,552	$6,540	$6,529	$6,517	$6,506	$6,462	$6,451	$6,440	$6,428	$6,417	$6,405	$77,810
31 - Clean Air Interstate Rule (CAIR) Compliance	Base	$3,044,156	$3,039,240	$3,038,950	$3,038,692	$3,034,338	$3,029,846	$3,010,323	$3,005,529	$3,000,757	$2,995,908	$2,990,845	$2,987,988	$36,216,575
31 - Clean Air Interstate Rule (CAIR) Compliance	Distribution	$9	$9	$9	$9	$9	$9	$9	$9	$9	$9	$8	$8	$103
31 - Clean Air Interstate Rule (CAIR) Compliance	Intermediate	$9,563	$9,546	$9,530	$9,514	$9,498	$9,481	$9,418	$9,402	$9,386	$9,370	$9,354	$9,338	$113,401
31 - Clean Air Interstate Rule (CAIR) Compliance	Peaking	$743,837	$742,414	$740,991	$739,567	$738,144	$736,721	$731,831	$730,417	$729,004	$727,590	$726,176	$724,763	$8,811,455
33 - MATS Project	Base	$783,097	$781,508	$795,626	$793,928	$792,230	$790,531	$785,285	$783,597	$781,910	$780,223	$778,536	$776,849	$9,423,322
34 - St Lucie Cooling Water System Inspection & Maintenance	Base	$29,675	$29,675	$29,675	$29,675	$29,675	$29,675	$29,477	$29,477	$29,478	$29,478	$29,478	$29,478	$354,914
35 - Martin Plant Drinking Water System Compliance	Intermediate	$971	$970	$968	$966	$964	$962	$956	$954	$952	$810	$668	$668	$10,809
35 - Martin Plant Drinking Water System Compliance	Peaking	$733	$731	$730	$729	$727	$726	$721	$720	$718	$611	$504	$504	$8,154
36 - Low-Level Radioactive Waste Storage	Base	$139,550	$139,284	$139,017	$138,751	$138,485	$138,218	$137,301	$137,036	$136,771	$136,506	$136,242	$135,977	$1,653,138
37 - DeSoto Next Generation Solar Energy Center	Solar	$1,018,746	$1,015,486	$1,012,372	$1,009,098	$1,005,634	$1,002,315	$988,163	$984,772	$981,526	$978,338	$975,150	$972,008	$11,943,610
38 - Space Coast Next Generation Solar Energy Center	Solar	$473,913	$472,478	$471,046	$469,611	$468,172	$466,737	$460,436	$458,852	$457,217	$455,683	$454,274	$452,879	$5,561,299
39 - Martin Next Generation Solar Energy Center	Intermediate	$2,890,502	$2,884,352	$2,879,010	$2,873,516	$2,866,652	$2,860,158	$2,821,076	$2,814,622	$2,807,750	$2,801,040	$2,794,844	$2,788,373	$34,081,894
41 - Manatee Temporary Heating System	Distribution	$1,518	$1,518	$1,518	$1,518	$1,518	$1,518	$1,508	$1,508	$1,508	$1,508	$1,508	$1,508	$18,161
41 - Manatee Temporary Heating System	Intermediate	$154,039	$153,729	$153,095	$152,462	$265,674	$277,668	$275,834	$274,531	$273,230	$271,931	$270,631	$269,331	$2,792,155
41 - Manatee Temporary Heating System	Peaking	$129,531	$129,147	$128,475	$127,803	$13,289	$0	$0	$0	$0	$0	$0	$0	$528,245
42 - Turkey Point Cooling Canal Monitoring Plan	Base	$462,688	$468,459	$470,238	$474,505	$429,258	$383,856	$387,967	$396,590	$404,962	$411,793	$416,456	$512,722	$5,219,496
42 - Turkey Point Cooling Canal Monitoring Plan	Intermediate	$0	$0	$0	$0	$63,923	$128,182	$127,758	$127,575	$127,355	$127,182	$127,005	$62,761	$891,741
44 - Martin Plant Barley Barber Swamp Iron Mitigation	Intermediate	$703	$701	$700	$699	$697	$696	$691	$690	$689	$688	$686	$685	$8,325
44 - Martin Plant Barley Barber Swamp Iron Mitigation	Peaking	$530	$529	$528	$527	$526	$525	$522	$521	$520	$519	$518	$517	$6,280
45 - 800 MW Unit ESP	Intermediate	$719	$716	$713	$711	$708	$705	$701	$698	$695	$693	$690	$687	$8,436
45 - 800 MW Unit ESP	Peaking	$1,585,780	$1,583,754	$1,581,832	$1,578,958	$1,576,081	$1,573,204	$1,562,763	$1,559,906	$1,557,049	$1,554,191	$1,551,333	$1,548,476	$18,813,326
47 - NPDES Permit Renewal Requirements	Base	$0	$0	$0	$0	$8	$585	$2,786	$5,965	$7,452	$7,453	$7,557	$11,563	$43,368
50 - Steam Electric Effluent Guidelines Revised Rules	Base	$6,556	$6,658	$6,867	$7,245	$7,736	$8,212	$8,507	$8,730	$9,273	$9,793	$10,068	$10,630	$100,275
54 - Coal Combustion Residuals	Base	$777,438	$778,972	$772,783	$779,875	$787,503	$834,867	$875,614	$879,399	$882,357	$887,108	$891,030	$920,693	$10,067,637
123-Protected Species Project	Intermediate	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10	$10
	Total	$12,990,460	$12,975,480	$12,968,667	$12,960,359	$12,961,467	$13,003,657	$12,943,349	$12,933,269	$12,920,618	$12,906,757	$12,890,363	$12,934,329	$155,388,774

[a] Each project's Total Recoverable Costs on Form 42-8A, Line 9.

FORM: 42-7A

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE FINAL TRUE-UP AMOUNT FOR THE PERIOD

JANUARY 2020 THROUGH DECEMBER 2020
CAPITAL INVESTMENT PROJECTS-RECOVERABLE COSTS

Capital Project [(a)]	Strata	Monthly Data	Jurisdictionalization		Method of Classification	
		Twelve Month Total	Jurisdictional Factor	Juris Twelve Month Amount	CP Demand	Energy
02 - Low NOX Burner Technology	Peaking	$57,069	95.1325%	$54,291	$0	$54,291
03 - Continuous Emission Monitoring Systems	Base	$27,625	95.8799%	$26,486	$0	$26,486
03 - Continuous Emission Monitoring Systems	Intermediate	$274,257	94.2430%	$258,468	$0	$258,468
03 - Continuous Emission Monitoring Systems	Peaking	$166,000	95.1325%	$157,920	$0	$157,920
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Base	$1,797	95.7922%	$1,721	$1,589	$132
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	General	$702,358	96.9124%	$680,672	$628,312	$52,359
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Intermediate	$224,012	94.1569%	$210,923	$194,698	$16,225
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Peaking	$715,226	95.0455%	$679,790	$627,499	$52,292
07 - Relocate Turbine Lube Oil Underground Piping to Above Ground	Base	$1,535	95.7922%	$1,471	$1,358	$113
08 - Oil Spill Clean-up/Response Equipment	Distribution	$265	100.0000%	$265	$245	$20
08 - Oil Spill Clean-up/Response Equipment	General	$330	96.9124%	$320	$295	$25
08 - Oil Spill Clean-up/Response Equipment	Intermediate	$125,605	94.1569%	$118,265	$109,168	$9,097
08 - Oil Spill Clean-up/Response Equipment	Peaking	$69,225	95.0455%	$65,795	$60,734	$5,061
10 - Relocate Storm Water Runoff	Base	$6,215	95.7922%	$5,953	$5,495	$458
12 - Scherer Discharge Pipeline	Base	$33,749	95.7922%	$32,329	$29,842	$2,487
20 - Wastewater Discharge Elimination & Reuse	Peaking	$42,408	95.0455%	$40,307	$37,207	$3,101
21 - St. Lucie Turtle Nets	Base	$734,751	95.7922%	$703,834	$649,693	$54,141
22 - Pipeline Integrity Management	Intermediate	$141,109	94.1569%	$132,864	$122,644	$10,220
22 - Pipeline Integrity Management	Peaking	$122,293	95.0455%	$116,234	$107,293	$8,941
23 - SPCC - Spill Prevention, Control & Countermeasures	Base	$339,502	95.7922%	$325,217	$300,200	$25,017
23 - SPCC - Spill Prevention, Control & Countermeasures	Distribution	$265,654	100.0000%	$265,654	$245,219	$20,435
23 - SPCC - Spill Prevention, Control & Countermeasures	General	$10,814	96.9124%	$10,480	$9,674	$806
23 - SPCC - Spill Prevention, Control & Countermeasures	Intermediate	$676,427	94.1569%	$636,902	$587,910	$48,992
23 - SPCC - Spill Prevention, Control & Countermeasures	Peaking	$540,937	95.0455%	$514,136	$474,587	$39,549
23 - SPCC - Spill Prevention, Control & Countermeasures	Transmission	$369,738	89.9387%	$332,538	$306,958	$25,580
24 - Manatee Plant Reburn	Peaking	$2,979,301	95.1325%	$2,834,282	$0	$2,834,282
26 - UST Remove/Replacement	General	$6,651	96.9124%	$6,446	$5,950	$496
28 - CWA 316(b) Phase II Rule	Intermediate	$77,810	94.1569%	$73,264	$67,628	$5,636
31 - Clean Air Interstate Rule (CAIR) Compliance	Base	$36,216,575	95.7922%	$34,692,653	$32,023,988	$2,668,666
31 - Clean Air Interstate Rule (CAIR) Compliance	Distribution	$103	100.0000%	$103	$95	$8
31 - Clean Air Interstate Rule (CAIR) Compliance	Intermediate	$113,401	94.1569%	$106,775	$98,561	$8,213
31 - Clean Air Interstate Rule (CAIR) Compliance	Peaking	$8,811,455	95.0455%	$8,374,890	$7,730,668	$644,222
33 - MATS Project	Base	$9,423,322	95.7922%	$9,026,807	$8,332,437	$694,370
34 - St Lucie Cooling Water System Inspection & Maintenance	Base	$354,914	95.7922%	$339,979	$313,827	$26,152
35 - Martin Plant Drinking Water System Compliance	Intermediate	$10,809	94.1569%	$10,177	$9,394	$783
35 - Martin Plant Drinking Water System Compliance	Peaking	$8,154	95.0455%	$7,750	$7,154	$596
36 - Low-Level Radioactive Waste Storage	Base	$1,653,138	95.7922%	$1,583,578	$1,461,764	$121,814
37 - DeSoto Next Generation Solar Energy Center	Solar	$11,943,610	95.7922%	$11,441,050	$10,560,969	$880,081
38 - Space Coast Next Generation Solar Energy Center	Solar	$5,561,299	95.7922%	$5,327,292	$4,917,500	$409,792
39 - Martin Next Generation Solar Energy Center	Intermediate	$34,081,894	94.1569%	$32,090,455	$29,621,958	$2,468,497
41 - Manatee Temporary Heating System	Distribution	$18,161	100.0000%	$18,161	$16,764	$1,397
41 - Manatee Temporary Heating System	Intermediate	$2,792,155	94.1569%	$2,629,005	$2,426,774	$202,231
41 - Manatee Temporary Heating System	Peaking	$528,245	95.0455%	$502,073	$463,452	$38,621
42 - Turkey Point Cooling Canal Monitoring Plan	Base	$5,219,496	95.7922%	$4,999,870	$4,615,264	$384,605
42 - Turkey Point Cooling Canal Monitoring Plan	Intermediate	$891,741	94.1569%	$839,636	$775,048	$64,587
44 - Martin Plant Barley Barber Swamp Iron Mitigation	Intermediate	$8,325	94.1569%	$7,839	$7,839	$0
44 - Martin Plant Barley Barber Swamp Iron Mitigation	Peaking	$6,280	95.0455%	$5,969	$5,969	$0
45 - 800 MW Unit ESP	Intermediate	$8,436	94.1569%	$7,943	$7,943	$0
45 - 800 MW Unit ESP	Peaking	$18,813,326	95.0455%	$17,881,218	$17,881,218	$0
47 - NPDES Permit Renewal Requirements	Base	$43,368	95.7922%	$41,543	$41,543	$0
50 - Steam Electric Effluent Guidelines Revised Rules	Base	$100,275	95.7922%	$96,055	$88,666	$7,389
54 - Coal Combustion Residuals	Base	$10,067,637	95.7922%	$9,644,011	$8,902,164	$741,847
NA-Amortization of Gains on Sales of Emissions Allowances	Base	($17)	95.7922%	($16)	($16)	$0
123-The Protected Species Project	Intermediate	$10	94.1569%	$9	$9	$0
	Total	$155,388,774		$147,961,655	$134,885,151	$13,076,502

[(a)] Each project's Total Recoverable Costs on Form 42-8A, Line 9.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE FINAL TRUE-UP AMOUNT FOR THE PERIOD

FORM: 42-7A

JANUARY 2020 THROUGH DECEMBER 2020
CAPITAL INVESTMENT PROJECTS-RECOVERABLE COSTS

RAD - ECRC - 42 - 7A - 2	Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	2020
2. Total of Capital Investment Projects	$12,990,460	$12,975,480	$12,968,667	$12,960,359	$12,961,467	$13,003,657	$12,943,349	$12,933,269	$12,920,618	$12,906,757	$12,890,363	$12,934,329	$155,388,774
3. Recoverable Costs Jurisdictionalized on Energy - Base	$2,348	$2,340	$2,332	$2,324	$2,316	$2,308	$2,293	$2,285	$2,277	$2,269	$2,261	$2,254	$27,608
Recoverable Costs Jurisdictionalized on Energy - Intermediate	$23,271	$23,203	$23,134	$23,065	$22,997	$22,930	$22,777	$22,710	$22,643	$22,576	$22,508	$22,441	$274,257
Recoverable Costs Jurisdictionalized on Energy - Peaking	$272,317	$271,402	$270,488	$269,573	$268,659	$267,745	$265,969	$265,060	$264,152	$263,244	$262,335	$261,427	$3,202,370
4. Recoverable Costs Jurisdictionalized on 12 CP Demand - Transmission	$31,134	$31,088	$31,047	$31,002	$30,958	$30,914	$30,710	$30,665	$30,621	$30,577	$30,533	$30,489	$369,738
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Base	$5,337,494	$5,337,950	$5,347,133	$5,356,467	$5,312,849	$5,309,228	$5,330,077	$5,338,963	$5,345,421	$5,350,545	$5,352,318	$5,477,827	$64,196,272
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Interm.	$3,159,903	$3,154,442	$3,148,529	$3,142,105	$3,312,089	$3,381,849	$3,340,078	$3,331,899	$3,323,374	$3,314,849	$3,306,980	$3,235,634	$39,151,732
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Peaking	$2,587,060	$2,582,891	$2,578,461	$2,573,071	$2,453,817	$2,435,723	$2,419,495	$2,414,794	$2,410,200	$2,405,409	$2,400,612	$2,396,017	$29,657,550
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Solar	$1,492,660	$1,487,964	$1,483,418	$1,478,708	$1,473,806	$1,469,052	$1,448,600	$1,443,624	$1,438,744	$1,434,021	$1,429,424	$1,424,887	$17,504,908
Recoverable Costs Jurisdictionalized on 12 CP Demand - General	$60,446	$60,404	$60,364	$60,314	$60,265	$60,217	$59,817	$59,766	$59,716	$59,665	$59,614	$59,566	$720,154
Recoverable Costs Jurisdictionalized on 12 CP Demand - Distribution	$23,828	$23,795	$23,762	$23,728	$23,710	$23,691	$23,534	$23,502	$23,469	$23,601	$23,777	$23,787	$284,184
5. Retail Production Energy Jurisdictional Factor - Base	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	
Retail Production Energy Jurisdictional Factor - Intermediate	94.24302%	94.24302%	94.24302%	94.24302%	94.24302%	94.24302%	94.24302%	94.24302%	94.24302%	94.24302%	94.24302%	94.24302%	
Retail Production Energy Jurisdictional Factor - Peaking	95.13247%	95.13247%	95.13247%	95.13247%	95.13247%	95.13247%	95.13247%	95.13247%	95.13247%	95.13247%	95.13247%	95.13247%	
6. Retail Transmission Demand Jurisdictional Factor	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	
Retail Production Demand Jurisdictional Factor - Base	95.79220%	95.79220%	95.79220%	95.79220%	95.79220%	95.79220%	95.79220%	95.79220%	95.79220%	95.79220%	95.79220%	95.79220%	
Retail Production Demand Jurisdictional Factor - Intermediate	94.15690%	94.15690%	94.15690%	94.15690%	94.15690%	94.15690%	94.15690%	94.15690%	94.15690%	94.15690%	94.15690%	94.15690%	
Retail Production Demand Jurisdictional Factor - Peaking	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	
Retail Production Demand Jurisdictional Factor - Solar	95.79220%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79220%	95.79223%	95.79223%	95.79223%	
Retail Production Demand Jurisdictional Factor - General	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%	
Retail Distribution Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	
7. Jurisdictional Recoverable Costs - Transmission	$28,001	$27,960	$27,923	$27,883	$27,843	$27,804	$27,620	$27,580	$27,540	$27,501	$27,461	$27,421	$332,538
Jurisdictional Recoverable Costs - Production - Base	$5,115,154	$5,115,583	$5,124,372	$5,133,306	$5,091,515	$5,088,040	$5,107,997	$5,116,501	$5,122,680	$5,127,581	$5,129,271	$5,249,492	$61,521,492
Jurisdictional Recoverable Costs - Production - Intermediate	$2,997,198	$2,991,992	$2,986,360	$2,980,246	$3,140,234	$3,205,854	$3,166,380	$3,158,616	$3,150,526	$3,142,436	$3,134,962	$3,067,722	$37,122,525
Jurisdictional Recoverable Costs - Production - Peaking	$2,717,946	$2,713,114	$2,708,033	$2,702,040	$2,587,825	$2,569,758	$2,552,644	$2,547,311	$2,542,081	$2,536,663	$2,531,240	$2,526,008	$31,234,662
Jurisdictional Recoverable Costs - Production - Solar	$1,429,852	$1,425,354	$1,420,999	$1,416,487	$1,411,791	$1,407,237	$1,387,646	$1,382,879	$1,378,204	$1,373,681	$1,369,277	$1,364,931	$16,768,337
Jurisdictional Recoverable Costs - General	$58,579	$58,539	$58,500	$58,452	$58,405	$58,357	$57,970	$57,921	$57,872	$57,823	$57,774	$57,727	$697,918
Jurisdictional Recoverable Costs - Distribution	$23,828	$23,795	$23,762	$23,728	$23,710	$23,691	$23,534	$23,502	$23,469	$23,601	$23,777	$23,787	$284,184
8. Total Jurisdictional Recoverable Costs for Capital Investment Activities	$12,370,558	$12,356,337	$12,349,948	$12,342,143	$12,341,323	$12,380,741	$12,323,789	$12,314,310	$12,302,372	$12,289,285	$12,273,762	$12,317,088	$147,961,655

FORM: 42-8A

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
02 - Low NOX Burner Technology														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)														
3a. Less: Accumulated Depreciation	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	
3b. Less: Capital Recovery Unamortized Balance	($263,079)	($259,947)	($256,815)	($253,683)	($250,552)	($247,420)	($244,288)	($241,156)	($238,024)	($234,892)	($231,760)	($228,628)	($225,496)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$263,079	$259,948	$256,816	$253,684	$250,552	$247,420	$244,288	$241,156	$238,024	$234,892	$231,760	$228,629	$225,497	
6. Average Net Investment		$261,514	$258,382	$255,250	$252,118	$248,986	$245,854	$242,722	$239,590	$236,458	$233,326	$230,195	$227,063	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$1,450	$1,432	$1,415	$1,398	$1,380	$1,363	$1,334	$1,317	$1,300	$1,282	$1,265	$1,248	$16,183
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$294	$291	$287	$284	$280	$277	$274	$270	$267	$263	$260	$256	$3,303
8. Investment Expenses														
a. Depreciation (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization (f)		$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$37,583
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$4,876	$4,855	$4,834	$4,813	$4,792	$4,771	$4,740	$4,719	$4,698	$4,678	$4,657	$4,636	$57,069

(a) Applicable to reserve salvage and removal cost

(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.

(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.

(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.

(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

(h) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.

Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FORM: 42-8A

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
03 - Continuous Emission Monitoring Systems														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$515,653	$515,653	$515,653	$515,653	$515,653	$515,653	$515,653	$515,653	$515,653	$515,653	$515,653	$515,653	$515,653	
3a. Less: Accumulated Depreciation	$405,100	$406,298	$407,497	$408,696	$409,895	$411,094	$412,293	$413,492	$414,691	$415,890	$417,089	$418,287	$419,486	
3b. Less: Capital Recovery Unamortized Balance	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$173,157	$171,958	$170,759	$169,560	$168,361	$167,162	$165,963	$164,764	$163,565	$162,366	$161,168	$159,969	$158,770	
6. Average Net Investment		$172,557	$171,358	$170,159	$168,960	$167,761	$166,563	$165,364	$164,165	$162,966	$161,767	$160,568	$159,369	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$956	$950	$943	$937	$930	$923	$909	$902	$896	$889	$883	$876	$10,994
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$194	$193	$192	$190	$189	$187	$187	$185	$184	$183	$181	$180	$2,244
8. Investment Expenses														
a. Depreciation (e)		$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$14,387
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$2,350	$2,342	$2,334	$2,326	$2,318	$2,310	$2,294	$2,286	$2,278	$2,271	$2,263	$2,255	$27,625

(a) Applicable to reserve salvage and removal cost

(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.

(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.

(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.

(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

(h) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.

Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8A

JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
03 - Continuous Emission Monitoring Systems														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$2,290,617	$2,290,617	$2,290,617	$2,290,167	$2,290,167	$2,290,167	$2,290,167	$2,290,167	$2,290,167	$2,290,167	$2,290,167	$2,290,167	$2,290,167	
3a. Less: Accumulated Depreciation	$521,499	$529,234	$536,970	$544,706	$552,442	$560,178	$567,914	$575,650	$583,386	$591,122	$598,858	$606,594	$614,329	
3b. Less: Capital Recovery Unamortized Balance	($203,055)	($200,638)	($198,221)	($195,803)	($193,386)	($190,969)	($188,552)	($186,134)	($183,717)	($181,300)	($178,882)	($176,465)	($174,048)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,972,174	$1,962,021	$1,951,868	$1,941,264	$1,931,111	$1,920,957	$1,910,804	$1,900,651	$1,890,498	$1,880,344	$1,870,191	$1,860,038	$1,849,885	
6. Average Net Investment		$1,967,097	$1,956,944	$1,946,566	$1,936,187	$1,926,034	$1,915,881	$1,905,728	$1,895,574	$1,885,421	$1,875,268	$1,865,115	$1,854,961	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$10,904	$10,847	$10,790	$10,732	$10,676	$10,620	$10,474	$10,418	$10,363	$10,307	$10,251	$10,195	$126,578
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$2,214	$2,203	$2,191	$2,179	$2,168	$2,157	$2,150	$2,139	$2,127	$2,116	$2,104	$2,093	$25,840
8. Investment Expenses														
a. Depreciation (e)		$7,736	$7,736	$7,736	$7,736	$7,736	$7,736	$7,736	$7,736	$7,736	$7,736	$7,736	$7,736	$92,831
b. Amortization (f)		$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$29,008
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$23,271	$23,203	$23,134	$23,065	$22,997	$22,930	$22,777	$22,710	$22,643	$22,576	$22,508	$22,441	$274,257

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
03 - Continuous Emission Monitoring Systems														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$1,201,724	$1,201,724	$1,201,724	$1,201,724	$1,201,724	$1,201,724	$1,201,724	$1,201,724	$1,201,724	$1,201,724	$1,201,724	$1,201,724	$1,201,724	
3a. Less: Accumulated Depreciation	$176,873	$181,410	$185,946	$190,483	$195,020	$199,556	$204,093	$208,629	$213,166	$217,702	$222,239	$226,776	$231,312	
3b. Less: Capital Recovery Unamortized Balance	($147,463)	($145,708)	($143,952)	($142,197)	($140,441)	($138,686)	($136,930)	($135,175)	($133,419)	($131,664)	($129,908)	($128,153)	($126,397)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,172,313	$1,166,021	$1,159,729	$1,153,437	$1,147,145	$1,140,853	$1,134,561	$1,128,269	$1,121,977	$1,115,685	$1,109,393	$1,103,101	$1,096,808	
6. Average Net Investment		$1,169,167	$1,162,875	$1,156,583	$1,150,291	$1,143,999	$1,137,707	$1,131,415	$1,125,123	$1,118,831	$1,112,539	$1,106,247	$1,099,955	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$6,481	$6,446	$6,411	$6,376	$6,341	$6,306	$6,218	$6,184	$6,149	$6,115	$6,080	$6,046	$75,153
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$1,316	$1,309	$1,302	$1,295	$1,288	$1,281	$1,276	$1,269	$1,262	$1,255	$1,248	$1,241	$15,342
8. Investment Expenses														
a. Depreciation (e)		$4,537	$4,537	$4,537	$4,537	$4,537	$4,537	$4,537	$4,537	$4,537	$4,537	$4,537	$4,537	$54,439
b. Amortization (f)		$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$21,066
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$14,089	$14,047	$14,005	$13,963	$13,921	$13,879	$13,787	$13,745	$13,704	$13,662	$13,620	$13,579	$166,000

(a) Applicable to reserve salvage and removal cost

(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.

(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.

(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.

(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

(h) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.

Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)														
3a. Less: Accumulated Depreciation														
3b. Less: Capital Recovery Unamortized Balance	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	
6. Average Net Investment		$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$125	$125	$125	$125	$125	$125	$124	$124	$124	$124	$124	$124	$1,492
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$25	$25	$25	$25	$25	$25	$25	$25	$25	$25	$25	$25	$305
8. Investment Expenses														
a. Depreciation (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$150	$150	$150	$150	$150	$150	$149	$149	$149	$149	$149	$149	$1,797

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks														
General														
1. Investments														
a. Expenditures/Additions		$292	$2,520	$517	$0	$585	$0	$0	$0	$0	$0	$0	$556	$4,470
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$5,837,840	$5,837,840	$5,837,840	$5,837,840	$5,837,840	$5,837,840	$5,837,840	$5,837,840	$5,837,840	$5,837,840	$5,837,840	$5,837,840	$5,837,840	
3a. Less: Accumulated Depreciation	$472,135	$479,433	$486,730	$494,027	$501,325	$508,622	$515,919	$523,216	$530,514	$537,811	$545,108	$552,406	$559,703	
4. CWIP Non-Interest Bearing	$2,382,912	$2,383,205	$2,385,725	$2,386,242	$2,386,242	$2,386,827	$2,386,827	$2,386,827	$2,386,827	$2,386,827	$2,386,827	$2,386,827	$2,387,383	
5. Net Investment (Lines 2 - 3 + 4)	$7,748,617	$7,741,612	$7,736,835	$7,730,055	$7,722,757	$7,716,045	$7,708,748	$7,701,450	$7,694,153	$7,686,856	$7,679,558	$7,672,261	$7,665,520	
6. Average Net Investment		$7,745,114	$7,739,223	$7,733,445	$7,726,406	$7,719,401	$7,712,396	$7,705,099	$7,697,802	$7,690,504	$7,683,207	$7,675,910	$7,668,890	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$42,932	$42,899	$42,867	$42,828	$42,789	$42,750	$42,348	$42,308	$42,268	$42,228	$42,188	$42,149	$510,555
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$8,718	$8,711	$8,705	$8,697	$8,689	$8,681	$8,693	$8,685	$8,676	$8,668	$8,660	$8,652	$104,235
8. Investment Expenses														
a. Depreciation (e)		$7,297	$7,297	$7,297	$7,297	$7,297	$7,297	$7,297	$7,297	$7,297	$7,297	$7,297	$7,297	$87,568
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$58,947	$58,908	$58,869	$58,822	$58,775	$58,729	$58,339	$58,290	$58,242	$58,194	$58,145	$58,099	$702,358

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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05 - Maintenance of Stationary Above Ground Fuel Storage Tanks														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	($76,136)	$0	$0	($76,136)
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	($76,136)	$0	$0	($76,136)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,214,496	$2,214,496	$2,214,496	
3a. Less: Accumulated Depreciation	$1,046,857	$1,052,825	$1,058,792	$1,064,759	$1,070,726	$1,076,693	$1,082,660	$1,088,627	$1,094,594	$1,100,561	$1,030,312	$1,036,120	$1,041,927	
3b. Less: Capital Recovery Unamortized Balance	($259,817)	($256,716)	($253,615)	($250,514)	($247,413)	($244,312)	($241,211)	($238,110)	($235,009)	($231,908)	($228,807)	($225,706)	($222,605)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,503,592	$1,494,524	$1,485,456	$1,476,388	$1,467,319	$1,458,251	$1,449,183	$1,440,115	$1,431,047	$1,421,979	$1,412,991	$1,404,083	$1,395,175	
6. Average Net Investment		$1,499,058	$1,489,990	$1,480,922	$1,471,854	$1,462,785	$1,453,717	$1,444,649	$1,435,581	$1,426,513	$1,417,485	$1,408,537	$1,399,629	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$8,309	$8,259	$8,209	$8,159	$8,108	$8,058	$7,940	$7,890	$7,840	$7,791	$7,742	$7,693	$95,998
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$1,687	$1,677	$1,667	$1,657	$1,647	$1,636	$1,630	$1,620	$1,609	$1,599	$1,589	$1,579	$19,597
8. Investment Expenses														
a. Depreciation (e)		$5,967	$5,967	$5,967	$5,967	$5,967	$5,967	$5,967	$5,967	$5,967	$5,887	$5,807	$5,807	$71,206
b. Amortization (f)		$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$37,212
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$19,065	$19,004	$18,944	$18,883	$18,823	$18,762	$18,638	$18,578	$18,518	$18,378	$18,239	$18,180	$224,012

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FORM: 42-8A

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	($57,436)	$0	$0	($57,436)
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	($57,436)	$0	$0	($57,436)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,459,114	$3,459,114	$3,459,114	
3a. Less: Accumulated Depreciation	$1,461,603	$1,472,778	$1,483,953	$1,495,129	$1,506,304	$1,517,480	$1,528,655	$1,539,831	$1,551,006	$1,562,181	$1,515,861	$1,526,915	$1,537,970	
3b. Less: Capital Recovery Unamortized Balance	($1,949,792)	($1,926,589)	($1,903,387)	($1,880,184)	($1,856,981)	($1,833,778)	($1,810,575)	($1,787,373)	($1,764,170)	($1,740,967)	($1,717,764)	($1,694,561)	($1,671,358)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$4,004,740	$3,970,362	$3,935,984	$3,901,605	$3,867,227	$3,832,849	$3,798,471	$3,764,092	$3,729,714	$3,695,336	$3,661,018	$3,626,760	$3,592,503	
6. Average Net Investment		$3,987,551	$3,953,173	$3,918,794	$3,884,416	$3,850,038	$3,815,660	$3,781,281	$3,746,903	$3,712,525	$3,678,177	$3,643,889	$3,609,631	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$22,103	$21,913	$21,722	$21,532	$21,341	$21,150	$20,783	$20,594	$20,405	$20,216	$20,027	$19,839	$251,624
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$4,488	$4,450	$4,411	$4,372	$4,334	$4,295	$4,266	$4,227	$4,188	$4,150	$4,111	$4,072	$51,365
8. Investment Expenses														
a. Depreciation (e)		$11,175	$11,175	$11,175	$11,175	$11,175	$11,175	$11,175	$11,175	$11,175	$11,115	$11,055	$11,055	$133,804
b. Amortization (f)		$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$278,434
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$60,970	$60,741	$60,511	$60,282	$60,053	$59,824	$59,427	$59,199	$58,971	$58,684	$58,396	$58,169	$715,226

(a) Applicable to reserve salvage and removal cost

(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.

(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.

(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.

(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

(h) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.

Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

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JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
07 - Relocate Turbine Lube Oil Underground Piping to Above Ground														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	
3a. Less: Accumulated Depreciation	$30,869	$31,001	$31,133	$31,265	$31,397	$31,529	$31,662	$31,794	$31,926	$32,058	$32,190	$32,322	$32,454	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$161	$29	($103)	($235)	($367)	($499)	($632)	($764)	($896)	($1,028)	($1,160)	($1,292)	($1,424)	
6. Average Net Investment		$95	($37)	($169)	($301)	($433)	($566)	($698)	($830)	($962)	($1,094)	($1,226)	($1,358)	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$1	($0)	($1)	($2)	($2)	($3)	($4)	($5)	($5)	($6)	($7)	($7)	($42)
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$0	($0)	($0)	($0)	($0)	($1)	($1)	($1)	($1)	($1)	($1)	($2)	($9)
8. Investment Expenses														
a. Depreciation (e)		$132	$132	$132	$132	$132	$132	$132	$132	$132	$132	$132	$132	$1,586
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$133	$132	$131	$130	$129	$128	$128	$127	$126	$125	$124	$123	$1,535

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
08 - Oil Spill Clean-up/Response Equipment														
Distribution														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	
3a. Less: Accumulated Depreciation	$389	$394	$399	$404	$409	$414	$419	$424	$429	$434	$439	$444	$449	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$2,607	$2,602	$2,597	$2,592	$2,587	$2,582	$2,577	$2,572	$2,567	$2,562	$2,557	$2,552	$2,547	
6. Average Net Investment		$2,604	$2,599	$2,594	$2,589	$2,584	$2,579	$2,574	$2,569	$2,564	$2,559	$2,554	$2,549	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$14	$14	$14	$14	$14	$14	$14	$14	$14	$14	$14	$14	$171
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$35
8. Investment Expenses														
a. Depreciation (e)		$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$60
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$265

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
08 - Oil Spill Clean-up/Response Equipment														
General														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	
3a. Less: Accumulated Depreciation	$1,069	$1,075	$1,080	$1,086	$1,091	$1,097	$1,102	$1,108	$1,114	$1,119	$1,125	$1,130	$1,136	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$3,343	$3,338	$3,332	$3,327	$3,321	$3,316	$3,310	$3,305	$3,299	$3,294	$3,288	$3,283	$3,277	
6. Average Net Investment		$3,341	$3,335	$3,330	$3,324	$3,319	$3,313	$3,308	$3,302	$3,296	$3,291	$3,285	$3,280	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$19	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18	$219
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$45
8. Investment Expenses														
a. Depreciation (e)		$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$66
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$28	$28	$28	$28	$28	$28	$27	$27	$27	$27	$27	$27	$330

(a) Applicable to reserve salvage and removal cost

(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.

(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.

(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.

(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

(h) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.

Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
08 - Oil Spill Clean-up/Response Equipment														
Intermediate														
1. Investments														
a. Expenditures/Additions		$318,963	$3,773	$974	$0	$4,088	$43,441	$14,095	$1,596	$2,788	$4,231	$49,226	$31,714	$474,888
b. Clearings to Plant		($21,141)	$0	$0	$0	$0	$0	$0	$0	$0	$5,655	$0	$117,883	$102,397
c. Retirements		($21,141)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($4,473)	($25,613)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$515,580	$494,439	$494,439	$494,439	$494,439	$494,439	$494,439	$494,439	$494,439	$494,439	$500,094	$500,094	$617,977	
3a. Less: Accumulated Depreciation	$8,720	($7,938)	($3,581)	$776	$5,132	$9,489	$13,846	$18,203	$22,560	$26,917	$31,281	$35,650	$35,658	
3b. Less: Capital Recovery Unamortized Balance	$154	$152	$150	$148	$146	$145	$143	$141	$139	$137	$135	$134	$132	
4. CWIP Non-Interest Bearing	$77,572	$396,534	$400,308	$401,282	$401,282	$405,369	$448,811	$462,905	$464,501	$467,289	$471,520	$520,746	$552,460	
5. Net Investment (Lines 2 - 3 + 4)	$584,278	$898,760	$898,178	$894,797	$890,441	$890,174	$929,260	$939,000	$936,240	$934,673	$940,197	$985,055	$1,134,647	
6. Average Net Investment		$741,519	$898,469	$896,487	$892,619	$890,308	$909,717	$934,130	$937,620	$935,457	$937,435	$962,626	$1,059,851	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$4,110	$4,980	$4,969	$4,948	$4,935	$5,043	$5,134	$5,153	$5,141	$5,152	$5,291	$5,825	$60,682
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$835	$1,011	$1,009	$1,005	$1,002	$1,024	$1,054	$1,058	$1,055	$1,058	$1,086	$1,196	$12,392
8. Investment Expenses														
a. Depreciation (e)		$4,483	$4,357	$4,357	$4,357	$4,357	$4,357	$4,357	$4,357	$4,357	$4,363	$4,370	$4,480	$52,552
b. Amortization (f)		($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($22)
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$9,426	$10,347	$10,334	$10,308	$10,292	$10,422	$10,543	$10,566	$10,552	$10,571	$10,745	$11,499	$125,605

(a) Applicable to reserve salvage and removal cost

(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.

(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.

(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.

(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

(h) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.

Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
08 - Oil Spill Clean-up/Response Equipment														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$2,555	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,555
b. Clearings to Plant		($15,948)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($3,391)	($19,340)
c. Retirements		($15,948)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($3,374)	($19,322)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$454,472	$438,523	$438,523	$438,523	$438,523	$438,523	$438,523	$438,523	$438,523	$438,523	$438,523	$438,523	$435,132	
3a. Less: Accumulated Depreciation	$132,037	$119,593	$123,002	$126,411	$129,820	$133,229	$136,638	$140,047	$143,456	$146,865	$150,274	$153,683	$153,698	
4. CWIP Non-Interest Bearing	$49,927	$49,927	$52,481	$52,481	$52,481	$52,481	$52,481	$52,481	$52,481	$52,481	$52,481	$52,481	$52,481	
5. Net Investment (Lines 2 - 3 + 4)	$372,361	$368,857	$368,003	$364,594	$361,185	$357,776	$354,367	$350,958	$347,549	$344,140	$340,731	$337,322	$333,916	
6. Average Net Investment		$370,609	$368,430	$366,298	$362,889	$359,480	$356,071	$352,662	$349,253	$345,844	$342,435	$339,026	$335,619	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$2,054	$2,042	$2,030	$2,012	$1,993	$1,974	$1,938	$1,920	$1,901	$1,882	$1,863	$1,845	$23,453
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$417	$415	$412	$408	$405	$401	$398	$394	$390	$386	$382	$379	$4,788
8. Investment Expenses														
a. Depreciation (e)		$3,504	$3,409	$3,409	$3,409	$3,409	$3,409	$3,409	$3,409	$3,409	$3,409	$3,409	$3,389	$40,983
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$5,975	$5,866	$5,852	$5,829	$5,806	$5,784	$5,745	$5,723	$5,700	$5,677	$5,655	$5,612	$69,225

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FORM: 42-8A

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
10 - Relocate Storm Water Runoff														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	
3a. Less: Accumulated Depreciation	$71,778	$71,999	$72,220	$72,441	$72,662	$72,883	$73,103	$73,324	$73,545	$73,766	$73,987	$74,208	$74,429	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$46,016	$45,795	$45,574	$45,353	$45,132	$44,911	$44,690	$44,470	$44,249	$44,028	$43,807	$43,586	$43,365	
6. Average Net Investment		$45,905	$45,684	$45,463	$45,243	$45,022	$44,801	$44,580	$44,359	$44,138	$43,917	$43,697	$43,476	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$254	$253	$252	$251	$250	$248	$245	$244	$243	$241	$240	$239	$2,960
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$52	$51	$51	$51	$51	$50	$50	$50	$50	$50	$49	$49	$604
8. Investment Expenses														
a. Depreciation (e)		$221	$221	$221	$221	$221	$221	$221	$221	$221	$221	$221	$221	$2,650
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$527	$526	$524	$523	$521	$520	$516	$515	$513	$512	$510	$509	$6,215

(a) Applicable to reserve salvage and removal cost

(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.

(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.

(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.

(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

(h) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.

Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
12 - Scherer Discharge Pipeline														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	
3a. Less: Accumulated Depreciation	$615,029	$616,302	$617,574	$618,847	$620,120	$621,392	$622,665	$623,937	$625,210	$626,483	$627,755	$629,028	$630,300	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$239,294	$238,022	$236,749	$235,477	$234,204	$232,931	$231,659	$230,386	$229,114	$227,841	$226,568	$225,296	$224,023	
6. Average Net Investment		$238,658	$237,386	$236,113	$234,840	$233,568	$232,295	$231,023	$229,750	$228,477	$227,205	$225,932	$224,660	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$1,323	$1,316	$1,309	$1,302	$1,295	$1,288	$1,270	$1,263	$1,256	$1,249	$1,242	$1,235	$15,345
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$269	$267	$266	$264	$263	$261	$261	$259	$258	$256	$255	$253	$3,133
8. Investment Expenses														
a. Depreciation (e)		$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$15,271
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$2,864	$2,856	$2,847	$2,839	$2,830	$2,822	$2,803	$2,795	$2,786	$2,778	$2,769	$2,761	$33,749

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
20 - Wastewater Discharge Elimination & Reuse														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)														
3a. Less: Accumulated Depreciation	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	
6. Average Net Investment		$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$2,947	$2,947	$2,947	$2,947	$2,947	$2,947	$2,922	$2,922	$2,922	$2,922	$2,922	$2,922	$35,218
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$598	$598	$598	$598	$598	$598	$600	$600	$600	$600	$600	$600	$7,190
8. Investment Expenses														
a. Depreciation (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$3,546	$3,546	$3,546	$3,546	$3,546	$3,546	$3,522	$3,522	$3,522	$3,522	$3,522	$3,522	$42,408

(a) Applicable to reserve salvage and removal cost

(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.

(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.

(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.

(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

(h) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.

Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
21 - St. Lucie Turtle Nets														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	
3a. Less: Accumulated Depreciation	($431,076)	($418,121)	($405,165)	($392,210)	($379,255)	($366,299)	($353,344)	($340,388)	($327,433)	($314,477)	($301,522)	($288,567)	($275,611)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$7,340,635	$7,327,679	$7,314,724	$7,301,769	$7,288,813	$7,275,858	$7,262,902	$7,249,947	$7,236,991	$7,224,036	$7,211,081	$7,198,125	$7,185,170	
6. Average Net Investment		$7,334,157	$7,321,202	$7,308,246	$7,295,291	$7,282,335	$7,269,380	$7,256,425	$7,243,469	$7,230,514	$7,217,558	$7,204,603	$7,191,647	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$40,654	$40,582	$40,510	$40,438	$40,366	$40,295	$39,882	$39,811	$39,740	$39,669	$39,598	$39,526	$481,071
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$8,255	$8,241	$8,226	$8,212	$8,197	$8,182	$8,187	$8,172	$8,157	$8,143	$8,128	$8,114	$98,214
8. Investment Expenses														
a. Depreciation (e)		$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$155,465
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$61,864	$61,778	$61,692	$61,605	$61,519	$61,432	$61,025	$60,939	$60,853	$60,767	$60,681	$60,595	$734,751

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8A

JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
22 - Pipeline Integrity Management														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$1,544,262	$1,544,262	$1,544,262	$1,544,262	$1,544,262	$1,544,262	$1,544,262	$1,544,262	$1,544,262	$1,544,262	$1,544,262	$1,544,262	$1,544,262	
3a. Less: Accumulated Depreciation	$263,059	$266,437	$269,815	$273,193	$276,571	$279,949	$283,327	$286,705	$290,083	$293,461	$296,839	$300,217	$303,596	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,281,203	$1,277,825	$1,274,447	$1,271,069	$1,267,691	$1,264,312	$1,260,934	$1,257,556	$1,254,178	$1,250,800	$1,247,422	$1,244,044	$1,240,666	
6. Average Net Investment		$1,279,514	$1,276,136	$1,272,758	$1,269,380	$1,266,002	$1,262,623	$1,259,245	$1,255,867	$1,252,489	$1,249,111	$1,245,733	$1,242,355	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$7,092	$7,074	$7,055	$7,036	$7,018	$6,999	$6,921	$6,902	$6,884	$6,865	$6,847	$6,828	$83,521
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$1,440	$1,436	$1,433	$1,429	$1,425	$1,421	$1,421	$1,417	$1,413	$1,409	$1,405	$1,402	$17,051
8. Investment Expenses														
a. Depreciation (e)		$3,378	$3,378	$3,378	$3,378	$3,378	$3,378	$3,378	$3,378	$3,378	$3,378	$3,378	$3,378	$40,537
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$11,911	$11,888	$11,866	$11,843	$11,821	$11,798	$11,720	$11,697	$11,675	$11,653	$11,630	$11,608	$141,109

(a) Applicable to reserve salvage and removal cost

(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.

(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.

(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.

(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

(h) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.

Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May

FLORIDA POWER & LIGHT COMPANY
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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
22 - Pipeline Integrity Management														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$1,328,530	$1,328,530	$1,328,530	$1,328,530	$1,328,530	$1,328,530	$1,328,530	$1,328,530	$1,328,530	$1,328,530	$1,328,530	$1,328,530	$1,328,530	
3a. Less: Accumulated Depreciation	$225,796	$228,777	$231,757	$234,737	$237,718	$240,698	$243,679	$246,659	$249,640	$252,620	$255,601	$258,581	$261,561	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,102,734	$1,099,753	$1,096,773	$1,093,792	$1,090,812	$1,087,831	$1,084,851	$1,081,870	$1,078,890	$1,075,910	$1,072,929	$1,069,949	$1,066,968	
6. Average Net Investment		$1,101,243	$1,098,263	$1,095,282	$1,092,302	$1,089,322	$1,086,341	$1,083,361	$1,080,380	$1,077,400	$1,074,419	$1,071,439	$1,068,459	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$6,104	$6,088	$6,071	$6,055	$6,038	$6,022	$5,954	$5,938	$5,922	$5,905	$5,889	$5,872	$71,858
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$1,240	$1,236	$1,233	$1,229	$1,226	$1,223	$1,222	$1,219	$1,216	$1,212	$1,209	$1,205	$14,670
8. Investment Expenses														
a. Depreciation (e)		$2,980	$2,980	$2,980	$2,980	$2,980	$2,980	$2,980	$2,980	$2,980	$2,980	$2,980	$2,980	$35,765
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$10,324	$10,304	$10,285	$10,265	$10,245	$10,225	$10,157	$10,137	$10,118	$10,098	$10,078	$10,058	$122,293

(a) Applicable to reserve salvage and removal cost

(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.

(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.

(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.

(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

(h) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.

Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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FORM: 42-8A

JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
23 - SPCC - Spill Prevention, Control & Countermeasures														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	
3a. Less: Accumulated Depreciation	$765,827	$778,128	$790,429	$802,729	$815,030	$827,331	$839,632	$851,933	$864,234	$876,534	$888,835	$901,136	$913,437	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$2,479,608	$2,467,307	$2,455,006	$2,442,705	$2,430,404	$2,418,103	$2,405,803	$2,393,502	$2,381,201	$2,368,900	$2,356,599	$2,344,298	$2,331,998	
6. Average Net Investment		$2,473,457	$2,461,156	$2,448,856	$2,436,555	$2,424,254	$2,411,953	$2,399,652	$2,387,351	$2,375,051	$2,362,750	$2,350,449	$2,338,148	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$13,711	$13,642	$13,574	$13,506	$13,438	$13,370	$13,189	$13,121	$13,054	$12,986	$12,918	$12,851	$159,359
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$2,784	$2,770	$2,756	$2,743	$2,729	$2,715	$2,707	$2,693	$2,680	$2,666	$2,652	$2,638	$32,533
8. Investment Expenses														
a. Depreciation (e)		$12,301	$12,301	$12,301	$12,301	$12,301	$12,301	$12,301	$12,301	$12,301	$12,301	$12,301	$12,301	$147,610
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$28,795	$28,713	$28,631	$28,549	$28,467	$28,385	$28,197	$28,116	$28,034	$27,953	$27,871	$27,790	$339,502

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
23 - SPCC - Spill Prevention, Control & Countermeasures														
Distribution														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	($20,503)	$0	$0	$210	$0	($125)	($60,505)	$0	($80,923)
b. Clearings to Plant		$0	$0	$0	$0	$20,503	$0	$0	$0	$0	$41,041	$60,505	$0	$122,048
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$3,406,962	$3,406,962	$3,406,962	$3,406,962	$3,406,962	$3,427,465	$3,427,465	$3,427,465	$3,427,465	$3,427,465	$3,468,506	$3,529,010	$3,529,010	
3a. Less: Accumulated Depreciation	$981,017	$986,000	$990,983	$995,967	$1,000,950	$1,005,948	$1,010,961	$1,015,974	$1,020,987	$1,026,000	$1,031,043	$1,036,160	$1,041,321	
4. CWIP Non-Interest Bearing	$170,083	$170,083	$170,083	$170,083	$170,083	$149,580	$149,580	$149,580	$149,790	$149,790	$149,665	$89,160	$89,160	
5. Net Investment (Lines 2 - 3 + 4)	$2,596,028	$2,591,045	$2,586,062	$2,581,078	$2,576,095	$2,571,097	$2,566,084	$2,561,071	$2,556,268	$2,551,255	$2,587,128	$2,582,011	$2,576,850	
6. Average Net Investment		$2,593,536	$2,588,553	$2,583,570	$2,578,587	$2,573,596	$2,568,591	$2,563,578	$2,558,670	$2,553,761	$2,569,191	$2,584,569	$2,579,430	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$14,376	$14,349	$14,321	$14,293	$14,266	$14,238	$14,090	$14,063	$14,036	$14,121	$14,205	$14,177	$170,534
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$2,919	$2,914	$2,908	$2,902	$2,897	$2,891	$2,892	$2,887	$2,881	$2,899	$2,916	$2,910	$34,816
8. Investment Expenses														
a. Depreciation (e)		$4,983	$4,983	$4,983	$4,983	$4,998	$5,013	$5,013	$5,013	$5,013	$5,043	$5,117	$5,161	$60,304
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$22,279	$22,245	$22,212	$22,179	$22,161	$22,142	$21,995	$21,963	$21,930	$22,062	$22,238	$22,248	$265,654

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
23 - SPCC - Spill Prevention, Control & Countermeasures														
General														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$146,691	$146,691	$146,691	$146,691	$146,691	$146,691	$146,691	$146,691	$146,691	$146,691	$146,691	$146,691	$146,691	
3a. Less: Accumulated Depreciation	$37,593	$37,776	$37,960	$38,143	$38,326	$38,510	$38,693	$38,876	$39,060	$39,243	$39,426	$39,610	$39,793	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$109,098	$108,915	$108,732	$108,548	$108,365	$108,182	$107,998	$107,815	$107,632	$107,448	$107,265	$107,082	$106,898	
6. Average Net Investment		$109,007	$108,823	$108,640	$108,457	$108,273	$108,090	$107,907	$107,723	$107,540	$107,357	$107,173	$106,990	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$604	$603	$602	$601	$600	$599	$593	$592	$591	$590	$589	$588	$7,153
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$123	$122	$122	$122	$122	$122	$122	$122	$121	$121	$121	$121	$1,460
8. Investment Expenses														
a. Depreciation (e)		$183	$183	$183	$183	$183	$183	$183	$183	$183	$183	$183	$183	$2,200
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$910	$909	$908	$907	$905	$904	$898	$897	$896	$895	$893	$892	$10,814

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8A

JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
23 - SPCC - Spill Prevention, Control & Countermeasures														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	($286,434)	$0	$0	$0	$43,154	$1,166	$929	$44,831	$1,856	$41,785	$10,225	($142,488)
b. Clearings to Plant		$0	$286,434	$0	$0	$0	$0	$0	$0	$0	($12,430)	$0	$0	$274,004
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	($12,430)	$0	$0	($12,430)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$4,983,517	$4,983,517	$5,269,951	$5,269,951	$5,269,951	$5,269,951	$5,269,951	$5,269,951	$5,269,951	$5,269,951	$5,257,521	$5,257,521	$5,257,521	
3a. Less: Accumulated Depreciation	$770,353	$782,234	$794,461	$807,035	$819,609	$832,182	$844,756	$857,330	$869,903	$882,477	$882,594	$895,113	$907,633	
3b. Less: Capital Recovery Unamortized Balance	($888,453)	($877,839)	($867,224)	($856,610)	($845,995)	($835,381)	($824,767)	($814,152)	($803,538)	($792,924)	($782,309)	($771,695)	($761,081)	
4. CWIP Non-Interest Bearing	$0	$0	($286,434)	($286,434)	($286,434)	($286,434)	($243,280)	($242,114)	($241,185)	($196,354)	($194,498)	($152,713)	($142,488)	
5. Net Investment (Lines 2 - 3 + 4)	$5,101,617	$5,079,121	$5,056,279	$5,033,091	$5,009,903	$4,986,715	$5,006,682	$4,984,660	$4,962,401	$4,984,044	$4,962,738	$4,981,389	$4,968,480	
6. Average Net Investment		$5,090,369	$5,067,700	$5,044,685	$5,021,497	$4,998,309	$4,996,699	$4,995,671	$4,973,530	$4,973,222	$4,973,391	$4,972,064	$4,974,934	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$28,216	$28,091	$27,963	$27,834	$27,706	$27,697	$27,457	$27,335	$27,334	$27,335	$27,327	$27,343	$331,638
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$5,730	$5,704	$5,678	$5,652	$5,626	$5,624	$5,636	$5,611	$5,611	$5,611	$5,609	$5,613	$67,706
8. Investment Expenses														
a. Depreciation (e)		$11,881	$12,228	$12,574	$12,574	$12,574	$12,574	$12,574	$12,574	$12,574	$12,547	$12,520	$12,520	$149,710
b. Amortization (f)		$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$127,372
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$56,442	$56,637	$56,829	$56,675	$56,520	$56,509	$56,281	$56,134	$56,132	$56,107	$56,071	$56,090	$676,427

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
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JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
23 - SPCC - Spill Prevention, Control & Countermeasures														
Peaking														
1. Investments														
a. Expenditures/Additions		$57,253	$0	$5,255	$0	$0	($19,642)	$880	$701	$33,820	$1,400	$31,522	$7,713	$118,902
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	($15,820)	$0	$0	($15,820)
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	($15,820)	$0	$0	($15,820)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$3,078,932	$3,078,932	$3,078,932	$3,078,932	$3,078,932	$3,078,932	$3,078,932	$3,078,932	$3,078,932	$3,078,932	$3,063,112	$3,063,112	$3,063,112	
3a. Less: Accumulated Depreciation	$1,305,659	$1,317,361	$1,329,063	$1,340,765	$1,352,467	$1,364,169	$1,375,871	$1,387,573	$1,399,275	$1,410,977	$1,406,824	$1,418,458	$1,430,091	
3b. Less: Capital Recovery Unamortized Balance	($1,097,801)	($1,084,770)	($1,071,738)	($1,058,706)	($1,045,675)	($1,032,643)	($1,019,612)	($1,006,580)	($993,549)	($980,517)	($967,486)	($954,454)	($941,423)	
4. CWIP Non-Interest Bearing	$276,713	$333,967	$333,967	$339,221	$339,221	$339,221	$319,580	$320,459	$321,160	$354,980	$356,380	$387,902	$395,615	
5. Net Investment (Lines 2 - 3 + 4)	$3,147,787	$3,180,307	$3,155,574	$3,136,095	$3,111,362	$3,086,628	$3,042,253	$3,018,399	$2,994,366	$3,003,453	$2,980,153	$2,987,010	$2,970,059	
6. Average Net Investment		$3,164,047	$3,167,940	$3,145,834	$3,123,728	$3,098,995	$3,064,440	$3,030,326	$3,006,383	$2,998,909	$2,991,803	$2,983,582	$2,978,535	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$17,538	$17,560	$17,438	$17,315	$17,178	$16,986	$16,655	$16,524	$16,482	$16,443	$16,398	$16,370	$202,889
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$3,561	$3,566	$3,541	$3,516	$3,488	$3,449	$3,419	$3,392	$3,383	$3,375	$3,366	$3,360	$41,418
8. Investment Expenses														
a. Depreciation (e)		$11,702	$11,702	$11,702	$11,702	$11,702	$11,702	$11,702	$11,702	$11,702	$11,668	$11,633	$11,633	$140,252
b. Amortization (f)		$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$156,378
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$45,833	$45,859	$45,712	$45,565	$45,400	$45,169	$44,807	$44,649	$44,599	$44,518	$44,429	$44,396	$540,937

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
23 - SPCC - Spill Prevention, Control & Countermeasures														
Transmission														
1. Investments														
a. Expenditures/Additions		($1,413)	$1,413	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	($297)	$0	$0	$0	$146	$0	$0	$0	$0	$0	$0	($151)
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$4,118,429	$4,118,429	$4,118,132	$4,118,132	$4,118,132	$4,118,132	$4,118,278	$4,118,278	$4,118,278	$4,118,278	$4,118,278	$4,118,278	$4,118,278	
3a. Less: Accumulated Depreciation	$445,391	$452,058	$458,724	$465,389	$472,055	$478,721	$485,387	$492,053	$498,719	$505,385	$512,051	$518,717	$525,383	
4. CWIP Non-Interest Bearing	$0	($1,413)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$3,673,038	$3,664,958	$3,659,409	$3,652,743	$3,646,077	$3,639,411	$3,632,891	$3,626,225	$3,619,559	$3,612,893	$3,606,227	$3,599,561	$3,592,895	
6. Average Net Investment		$3,668,998	$3,662,184	$3,656,076	$3,649,410	$3,642,744	$3,636,151	$3,629,558	$3,622,892	$3,616,226	$3,609,560	$3,602,894	$3,596,228	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$20,337	$20,300	$20,266	$20,229	$20,192	$20,155	$19,949	$19,912	$19,875	$19,839	$19,802	$19,765	$240,621
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$4,130	$4,122	$4,115	$4,108	$4,100	$4,093	$4,095	$4,087	$4,080	$4,072	$4,065	$4,057	$49,125
8. Investment Expenses														
a. Depreciation (e)		$6,666	$6,666	$6,666	$6,666	$6,666	$6,666	$6,666	$6,666	$6,666	$6,666	$6,666	$6,666	$79,992
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$31,134	$31,088	$31,047	$31,002	$30,958	$30,914	$30,710	$30,665	$30,621	$30,577	$30,533	$30,489	$369,738

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
24 - Manatee Plant Reburn														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	
3a. Less: Accumulated Depreciation	$12,957,135	$13,084,831	$13,212,527	$13,340,223	$13,467,920	$13,595,616	$13,723,312	$13,851,008	$13,978,705	$14,106,401	$14,234,097	$14,361,793	$14,489,489	
4. CWIP Non-Interest Bearing	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	
5. Net Investment (Lines 2 - 3 + 4)	$18,906,584	$18,778,888	$18,651,191	$18,523,495	$18,395,799	$18,268,103	$18,140,407	$18,012,710	$17,885,014	$17,757,318	$17,629,622	$17,501,925	$17,374,229	
6. Average Net Investment		$18,842,736	$18,715,039	$18,587,343	$18,459,647	$18,331,951	$18,204,255	$18,076,558	$17,948,862	$17,821,166	$17,693,470	$17,565,774	$17,438,077	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$104,446	$103,739	$103,031	$102,323	$101,615	$100,907	$99,352	$98,650	$97,948	$97,246	$96,544	$95,842	$1,201,643
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$21,209	$21,066	$20,922	$20,778	$20,634	$20,491	$20,394	$20,250	$20,106	$19,962	$19,818	$19,674	$245,303
8. Investment Expenses														
a. Depreciation (e)		$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$1,532,355
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$253,352	$252,500	$251,649	$250,797	$249,946	$249,094	$247,442	$246,596	$245,750	$244,904	$244,058	$243,212	$2,979,301

(a) Applicable to reserve salvage and removal cost

(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.

(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.

(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.

(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

(h) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.

Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
26 - UST Remove/Replacement														
General														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	
3a. Less: Accumulated Depreciation	$52,903	$53,047	$53,192	$53,336	$53,480	$53,625	$53,769	$53,913	$54,057	$54,202	$54,346	$54,490	$54,635	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$62,544	$62,399	$62,255	$62,111	$61,966	$61,822	$61,678	$61,534	$61,389	$61,245	$61,101	$60,956	$60,812	
6. Average Net Investment		$62,472	$62,327	$62,183	$62,039	$61,894	$61,750	$61,606	$61,461	$61,317	$61,173	$61,028	$60,884	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$346	$345	$345	$344	$343	$342	$339	$338	$337	$336	$335	$335	$4,085
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$70	$70	$70	$70	$70	$70	$70	$69	$69	$69	$69	$69	$834
8. Investment Expenses														
a. Depreciation (e)		$144	$144	$144	$144	$144	$144	$144	$144	$144	$144	$144	$144	$1,732
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$561	$560	$559	$558	$557	$556	$552	$551	$550	$550	$549	$548	$6,651

(a) Applicable to reserve salvage and removal cost

(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.

(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.

(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.

(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

(h) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.

Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
28 - CWA 316(b) Phase II Rule														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$771,310	$771,310	$771,310	$771,310	$771,310	$771,310	$771,310	$771,310	$771,310	$771,310	$771,310	$771,310	$771,310	
3a. Less: Accumulated Depreciation	$45,515	$47,244	$48,973	$50,702	$52,431	$54,160	$55,889	$57,618	$59,347	$61,076	$62,805	$64,535	$66,264	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$725,795	$724,066	$722,337	$720,608	$718,879	$717,150	$715,421	$713,692	$711,963	$710,234	$708,505	$706,776	$705,047	
6. Average Net Investment		$724,931	$723,202	$721,473	$719,744	$718,014	$716,285	$714,556	$712,827	$711,098	$709,369	$707,640	$705,911	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$4,018	$4,009	$3,999	$3,990	$3,980	$3,970	$3,927	$3,918	$3,908	$3,899	$3,889	$3,880	$47,388
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$816	$814	$812	$810	$808	$806	$806	$804	$802	$800	$798	$796	$9,674
8. Investment Expenses														
a. Depreciation (e)		$1,729	$1,729	$1,729	$1,729	$1,729	$1,729	$1,729	$1,729	$1,729	$1,729	$1,729	$1,729	$20,748
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$6,563	$6,552	$6,540	$6,529	$6,517	$6,506	$6,462	$6,451	$6,440	$6,428	$6,417	$6,405	$77,810

(a) Applicable to reserve salvage and removal cost

(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.

(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.

(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.

(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

(h) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.

Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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31 - Clean Air Interstate Rule (CAIR) Compliance														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$1,637,989	$159,296	$87,244	$91,279	$55,525	$97,362	$32,422	$32,647	($2,193,764)	$0
b. Clearings to Plant		($0)	$92,532	$1,076,639	($1,169,171)	$0	$0	($268)	$0	$0	$0	$0	$2,240,564	$2,240,296
c. Retirements		$0	$0	$0	$0	$0	$0	($268)	$0	$0	$0	$0	$0	($268)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
2. Plant-In-Service/Depreciation Base (b)	$359,943,378	$359,943,378	$360,035,910	$361,112,549	$359,943,378	$359,943,378	$359,943,378	$359,943,110	$359,943,110	$359,943,110	$359,943,110	$359,943,110	$362,183,674	
3a. Less: Accumulated Depreciation	$65,990,209	$66,787,065	$67,584,011	$68,382,087	$69,180,073	$69,976,929	$70,773,786	$71,570,372	$72,367,225	$73,164,078	$73,960,931	$74,757,784	$75,556,803	
3b. Less: Capital Recovery Unamortized Balance	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$1,637,989	$1,797,285	$1,884,529	$1,975,807	$2,031,333	$2,128,695	$2,161,117	$2,193,764	$0	
5. Net Investment (Lines 2 - 3 + 4)	$337,392,700	$336,595,843	$335,891,430	$336,169,993	$335,840,824	$335,203,264	$334,493,652	$333,788,076	$333,046,748	$332,347,257	$331,582,826	$330,818,620	$330,066,401	
6. Average Net Investment		$336,994,272	$336,243,637	$336,030,711	$336,005,409	$335,522,044	$334,848,458	$334,140,864	$333,417,412	$332,697,003	$331,965,042	$331,200,723	$330,442,510	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$1,867,979	$1,863,818	$1,862,638	$1,862,498	$1,859,818	$1,856,085	$1,836,491	$1,832,515	$1,828,555	$1,824,532	$1,820,331	$1,816,164	$22,131,425
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$379,321	$378,476	$378,236	$378,208	$377,664	$376,905	$376,978	$376,162	$375,349	$374,523	$373,661	$372,805	$4,518,286
8. Investment Expenses														
a. Depreciation (e)		$796,856	$796,946	$798,076	$797,986	$796,856	$796,856	$796,855	$796,853	$796,853	$796,853	$796,853	$799,019	$9,566,863
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$3,044,156	$3,039,240	$3,038,950	$3,038,692	$3,034,338	$3,029,846	$3,010,323	$3,005,529	$3,000,757	$2,995,908	$2,990,845	$2,987,988	$36,216,575

(a) Applicable to reserve salvage and removal cost

(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.

(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.

(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.

(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

(h) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.

Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8A

JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
31 - Clean Air Interstate Rule (CAIR) Compliance														
Distribution														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	
3a. Less: Accumulated Depreciation	$426	$429	$432	$435	$438	$440	$443	$446	$449	$452	$454	$457	$460	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$886	$884	$881	$878	$875	$872	$869	$867	$864	$861	$858	$855	$853	
6. Average Net Investment		$885	$882	$879	$877	$874	$871	$868	$865	$862	$860	$857	$854	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$58
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$12
8. Investment Expenses														
a. Depreciation (e)		$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$34
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$9	$9	$9	$9	$9	$9	$9	$9	$9	$9	$8	$8	$103

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
31 - Clean Air Interstate Rule (CAIR) Compliance														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$1,278,330	$1,278,330	$1,278,330	$1,278,330	$1,278,330	$1,278,330	$1,278,330	$1,278,330	$1,278,330	$1,278,330	$1,278,330	$1,278,330	$1,278,330	
3a. Less: Accumulated Depreciation	$208,356	$210,792	$213,227	$215,663	$218,098	$220,533	$222,969	$225,404	$227,840	$230,275	$232,711	$235,146	$237,582	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,069,974	$1,067,538	$1,065,103	$1,062,667	$1,060,232	$1,057,797	$1,055,361	$1,052,926	$1,050,490	$1,048,055	$1,045,619	$1,043,184	$1,040,748	
6. Average Net Investment		$1,068,756	$1,066,321	$1,063,885	$1,061,450	$1,059,014	$1,056,579	$1,054,143	$1,051,708	$1,049,273	$1,046,837	$1,044,402	$1,041,966	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$5,924	$5,911	$5,897	$5,884	$5,870	$5,857	$5,794	$5,780	$5,767	$5,754	$5,740	$5,727	$69,904
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$1,203	$1,200	$1,198	$1,195	$1,192	$1,189	$1,189	$1,187	$1,184	$1,181	$1,178	$1,176	$14,271
8. Investment Expenses														
a. Depreciation (e)		$2,435	$2,435	$2,435	$2,435	$2,435	$2,435	$2,435	$2,435	$2,435	$2,435	$2,435	$2,435	$29,225
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$9,563	$9,546	$9,530	$9,514	$9,498	$9,481	$9,418	$9,402	$9,386	$9,370	$9,354	$9,338	$113,401

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
31 - Clean Air Interstate Rule (CAIR) Compliance														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$55,890,251	$55,890,251	$55,890,251	$55,890,251	$55,890,251	$55,890,251	$55,890,251	$55,890,251	$55,890,251	$55,890,251	$55,890,251	$55,890,251	$55,890,251	
3a. Less: Accumulated Depreciation	($23,703,096)	($23,490,331)	($23,277,566)	($23,064,801)	($22,852,035)	($22,639,270)	($22,426,505)	($22,213,740)	($22,000,974)	($21,788,209)	($21,575,444)	($21,362,679)	($21,149,914)	
3b. Less: Capital Recovery Unamortized Balance	($53,967)	($53,325)	($52,682)	($52,040)	($51,397)	($50,755)	($50,112)	($49,470)	($48,827)	($48,185)	($47,542)	($46,900)	($46,257)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$79,647,314	$79,433,906	$79,220,499	$79,007,091	$78,793,683	$78,580,275	$78,366,868	$78,153,460	$77,940,052	$77,726,645	$77,513,237	$77,299,829	$77,086,422	
6. Average Net Investment		$79,540,610	$79,327,202	$79,113,795	$78,900,387	$78,686,979	$78,473,572	$78,260,164	$78,046,756	$77,833,349	$77,619,941	$77,406,533	$77,193,125	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$440,898	$439,715	$438,532	$437,349	$436,167	$434,984	$430,130	$428,957	$427,784	$426,611	$425,439	$424,266	$5,190,833
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$89,531	$89,291	$89,050	$88,810	$88,570	$88,330	$88,293	$88,052	$87,812	$87,571	$87,330	$87,089	$1,059,729
8. Investment Expenses														
a. Depreciation (e)		$212,765	$212,765	$212,765	$212,765	$212,765	$212,765	$212,765	$212,765	$212,765	$212,765	$212,765	$212,765	$2,553,183
b. Amortization (f)		$642	$642	$642	$642	$642	$642	$642	$642	$642	$642	$642	$642	$7,710
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$743,837	$742,414	$740,991	$739,567	$738,144	$736,721	$731,831	$730,417	$729,004	$727,590	$726,176	$724,763	$8,811,455

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
33 - MATS Project														
Base														
1. Investments														
a. Expenditures/Additions		($70,751)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($0)	($70,751)
b. Clearings to Plant		($3,443,476)	$3,514,226	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$70,751
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$109,260,738	$105,817,263	$109,331,489	$109,331,489	$109,331,489	$109,331,489	$109,331,489	$109,331,489	$109,331,489	$109,331,489	$109,331,489	$109,331,489	$109,331,489	
3a. Less: Accumulated Depreciation	$27,669,247	$27,919,758	$28,170,352	$28,425,031	$28,679,710	$28,934,389	$29,189,068	$29,443,747	$29,698,426	$29,953,105	$30,207,784	$30,462,463	$30,717,142	
3b. Less: Capital Recovery Unamortized Balance	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	
4. CWIP Non-Interest Bearing	$70,755	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	
5. Net Investment (Lines 2 - 3 + 4)	$81,746,314	$77,981,576	$81,245,208	$80,990,529	$80,735,850	$80,481,171	$80,226,492	$79,971,813	$79,717,134	$79,462,455	$79,207,776	$78,953,097	$78,698,418	
6. Average Net Investment		$79,863,945	$79,613,392	$81,117,869	$80,863,190	$80,608,511	$80,353,832	$80,099,153	$79,844,474	$79,589,795	$79,335,116	$79,080,437	$78,825,758	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$442,691	$441,302	$449,641	$448,229	$446,818	$445,406	$440,238	$438,838	$437,438	$436,038	$434,639	$433,239	$5,294,516
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$89,895	$89,613	$91,306	$91,020	$90,733	$90,446	$90,368	$90,081	$89,793	$89,506	$89,219	$88,931	$1,080,910
8. Investment Expenses														
a. Depreciation (e)		$250,512	$250,594	$254,679	$254,679	$254,679	$254,679	$254,679	$254,679	$254,679	$254,679	$254,679	$254,679	$3,047,896
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$783,097	$781,508	$795,626	$793,928	$792,230	$790,531	$785,285	$783,597	$781,910	$780,223	$778,536	$776,849	$9,423,322

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
34 - St Lucie Cooling Water System Inspection & Maintenance														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$96	$0	$0	$0	$96
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)														
3a. Less: Accumulated Depreciation														
4. CWIP Non-Interest Bearing	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,942	$4,449,942	$4,449,942	$4,449,942	
5. Net Investment (Lines 2 - 3 + 4)	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,942	$4,449,942	$4,449,942	$4,449,942	
6. Average Net Investment		$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,894	$4,449,942	$4,449,942	$4,449,942	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$24,666	$24,666	$24,666	$24,666	$24,666	$24,666	$24,457	$24,457	$24,457	$24,458	$24,458	$24,458	$294,739
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$5,009	$5,009	$5,009	$5,009	$5,009	$5,009	$5,020	$5,020	$5,020	$5,020	$5,020	$5,020	$60,175
8. Investment Expenses														
a. Depreciation (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$29,675	$29,675	$29,675	$29,675	$29,675	$29,675	$29,477	$29,477	$29,478	$29,478	$29,478	$29,478	$354,914

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019
Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for
the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report
and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the
Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
35 - Martin Plant Drinking Water System Compliance														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	($134,173)	$0	$0	($134,173)
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	($134,173)	$0	$0	($134,173)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$134,173	$134,173	$134,173	$134,173	$134,173	$134,173	$134,173	$134,173	$134,173	$134,173				
3a. Less: Accumulated Depreciation	$30,605	$30,887	$31,169	$31,451	$31,732	$32,014	$32,296	$32,578	$32,859	$33,141	($100,891)	($100,891)	($100,891)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$103,568	$103,286	$103,004	$102,722	$102,440	$102,159	$101,877	$101,595	$101,313	$101,032	$100,891	$100,891	$100,891	
6. Average Net Investment		$103,427	$103,145	$102,863	$102,581	$102,300	$102,018	$101,736	$101,454	$101,173	$100,961	$100,891	$100,891	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$573	$572	$570	$569	$567	$565	$559	$558	$556	$555	$555	$555	$6,753
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$116	$116	$116	$115	$115	$115	$115	$114	$114	$114	$114	$114	$1,379
8. Investment Expenses														
a. Depreciation (e)		$282	$282	$282	$282	$282	$282	$282	$282	$282	$141	$0	$0	$2,677
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$971	$970	$968	$966	$964	$962	$956	$954	$952	$810	$668	$668	$10,809

(a) Applicable to reserve salvage and removal cost

(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.

(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.

(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.

(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

(h) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.

Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
35 - Martin Plant Drinking Water System Compliance														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	($101,218)	$0	$0	($101,218)
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	($101,218)	$0	$0	($101,218)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$101,218	$101,218	$101,218	$101,218	$101,218	$101,218	$101,218	$101,218	$101,218	$101,218				
3a. Less: Accumulated Depreciation	$23,088	$23,301	$23,513	$23,726	$23,938	$24,151	$24,364	$24,576	$24,789	$25,001	($76,111)	($76,111)	($76,111)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$78,130	$77,917	$77,705	$77,492	$77,280	$77,067	$76,855	$76,642	$76,429	$76,217	$76,111	$76,111	$76,111	
6. Average Net Investment		$78,024	$77,811	$77,598	$77,386	$77,173	$76,961	$76,748	$76,536	$76,323	$76,164	$76,111	$76,111	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$432	$431	$430	$429	$428	$427	$422	$421	$419	$419	$418	$418	$5,094
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$88	$88	$87	$87	$87	$87	$87	$86	$86	$86	$86	$86	$1,040
8. Investment Expenses														
a. Depreciation (e)		$213	$213	$213	$213	$213	$213	$213	$213	$213	$106	$0	$0	$2,019
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$733	$731	$730	$729	$727	$726	$721	$720	$718	$611	$504	$504	$8,154

(a) Applicable to reserve salvage and removal cost

(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.

(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.

(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.

(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

(h) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.

Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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36 - Low-Level Radioactive Waste Storage														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	
3a. Less: Accumulated Depreciation	$2,502,548	$2,542,506	$2,582,465	$2,622,424	$2,662,383	$2,702,342	$2,742,300	$2,782,259	$2,822,218	$2,862,177	$2,902,136	$2,942,094	$2,982,053	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$14,954,256	$14,914,297	$14,874,338	$14,834,380	$14,794,421	$14,754,462	$14,714,503	$14,674,544	$14,634,586	$14,594,627	$14,554,668	$14,514,709	$14,474,750	
6. Average Net Investment		$14,934,277	$14,894,318	$14,854,359	$14,814,400	$14,774,441	$14,734,483	$14,694,524	$14,654,565	$14,614,606	$14,574,647	$14,534,689	$14,494,730	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$82,782	$82,560	$82,339	$82,117	$81,896	$81,674	$80,763	$80,544	$80,324	$80,105	$79,885	$79,665	$974,653
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$16,810	$16,765	$16,720	$16,675	$16,630	$16,585	$16,578	$16,533	$16,488	$16,443	$16,398	$16,353	$198,979
8. Investment Expenses														
a. Depreciation (e)		$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$479,506
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$139,550	$139,284	$139,017	$138,751	$138,485	$138,218	$137,301	$137,036	$136,771	$136,506	$136,242	$135,977	$1,653,138

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
37 - DeSoto Next Generation Solar Energy Center														
Solar														
1. Investments														
a. Expenditures/Additions		$0	$1,062	$1,208	$5,083	$47	$0	$0	$0	$0	($7,409)	$0	$0	($9)
b. Clearings to Plant		($1,886)	($1,454)	$9,909	($32,614)	($5,129)	($5,547)	($17,386)	($8,446)	$0	($8,638)	$0	$2,267	($68,924)
c. Retirements		($1,886)	($1,454)	$0	($32,614)	($5,129)	($5,547)	($17,386)	($11,560)	$0	($16,380)	$0	$0	($91,957)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$153,561,354	$153,559,468	$153,558,013	$153,567,922	$153,535,308	$153,530,179	$153,524,632	$153,507,246	$153,498,800	$153,498,800	$153,490,163	$153,490,163	$153,492,429	
3a. Less: Accumulated Depreciation	$52,081,935	$52,525,767	$52,969,983	$53,415,717	$53,828,725	$54,268,953	$54,708,658	$55,136,346	$55,569,624	$56,014,369	$56,442,709	$56,887,403	$57,332,110	
4. CWIP Non-Interest Bearing	$10	$10	$1,072	$2,280	$7,363	$7,410	$7,410	$7,410	$7,410	$7,410	$1	$1	$1	
5. Net Investment (Lines 2 - 3 + 4)	$101,479,428	$101,033,711	$100,589,102	$100,154,485	$99,713,947	$99,268,637	$98,823,384	$98,378,310	$97,936,587	$97,491,841	$97,047,455	$96,602,761	$96,160,320	
6. Average Net Investment		$101,256,570	$100,811,406	$100,371,794	$99,934,216	$99,491,292	$99,046,011	$98,600,847	$98,157,448	$97,714,214	$97,269,648	$96,825,108	$96,381,540	
a. Average ITC Balance		$28,990,785	$28,868,719	$28,746,653	$28,624,587	$28,502,521	$28,380,455	$28,258,389	$28,136,323	$28,014,257	$27,892,191	$27,770,125	$27,648,059	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$611,952	$609,271	$606,621	$603,982	$601,314	$598,632	$585,104	$582,481	$579,858	$577,228	$574,599	$571,974	$7,103,018
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$121,471	$120,939	$120,412	$119,888	$119,358	$118,825	$118,380	$117,848	$117,318	$116,785	$116,253	$115,722	$1,423,200
8. Investment Expenses														
a. Depreciation (e)		$433,531	$433,484	$433,547	$433,435	$433,170	$433,065	$432,887	$432,651	$432,559	$432,533	$432,507	$432,520	$5,195,888
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$146,244
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($1,924,740)
9. Total System Recoverable Costs (Lines 7 & 8)		$1,018,746	$1,015,486	$1,012,372	$1,009,098	$1,005,634	$1,002,315	$988,163	$984,772	$981,526	$978,338	$975,150	$972,008	$11,943,610

(a) Applicable to reserve salvage and removal cost

(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.

(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.

(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.

(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

(h) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.

Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
38 - Space Coast Next Generation Solar Energy Center														
Solar														
1. Investments														
a. Expenditures/Additions		$0	$0	$1,110	($871)	$0	$0	$0	($339)	$0	$667	$0	($664)	($98)
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	($8,680)	($11,560)	($14,962)	$0	$0	$1,105	($34,097)
c. Retirements		$0	$0	$0	$0	$0	$0	($8,680)	($11,560)	($14,962)	$0	$0	$0	($35,202)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$70,591,411	$70,591,411	$70,591,411	$70,591,411	$70,591,411	$70,591,411	$70,591,411	$70,582,731	$70,571,171	$70,556,209	$70,556,209	$70,556,209	$70,557,314	
3a. Less: Accumulated Depreciation	$23,056,153	$23,256,037	$23,455,921	$23,655,805	$23,855,688	$24,055,572	$24,255,456	$24,446,587	$24,634,670	$24,819,130	$25,018,427	$25,217,724	$25,417,036	
4. CWIP Non-Interest Bearing	$98	$98	$98	$1,208	$337	$337	$337	$337	($2)	($2)	$664	$664	$0	
5. Net Investment (Lines 2 - 3 + 4)	$47,535,356	$47,335,472	$47,135,588	$46,936,815	$46,736,060	$46,536,176	$46,336,292	$46,136,481	$45,936,499	$45,737,077	$45,538,446	$45,339,149	$45,140,278	
6. Average Net Investment		$47,435,414	$47,235,530	$47,036,201	$46,836,437	$46,636,118	$46,436,234	$46,236,386	$46,036,490	$45,836,788	$45,637,762	$45,438,798	$45,239,714	
a. Average ITC Balance		$12,438,795	$12,387,606	$12,336,417	$12,285,228	$12,234,039	$12,182,850	$12,131,661	$12,080,472	$12,029,283	$11,978,094	$11,926,905	$11,875,716	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$284,683	$283,485	$282,291	$281,094	$279,894	$278,697	$272,660	$271,483	$270,307	$269,135	$267,963	$266,791	$3,308,481
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$56,610	$56,372	$56,134	$55,896	$55,657	$55,419	$55,228	$54,990	$54,752	$54,514	$54,277	$54,039	$663,888
8. Investment Expenses														
a. Depreciation (e)		$195,492	$195,492	$195,492	$195,492	$195,492	$195,492	$195,419	$195,251	$195,030	$194,905	$194,905	$194,920	$2,343,381
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$52,704
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($807,156)
9. Total System Recoverable Costs (Lines 7 & 8)		$473,913	$472,478	$471,046	$469,611	$468,172	$466,737	$460,436	$458,852	$457,217	$455,683	$454,274	$452,879	$5,561,299

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
39 - Martin Next Generation Solar Energy Center														
Intermediate														
1. Investments														
a. Expenditures/Additions		($1,781,021)	$71,071	$403,010	$129,180	$28,970	$170,413	$187,431	$43,345	$113,110	$57,046	$128,375	($75,003)	($524,072)
b. Clearings to Plant		$569,415	$61,820	$6,695	($95,126)	$95,461	$17,202	$3,005	$66,146	($111,918)	$49,239	$192,506	$80,426	$934,872
c. Retirements		($1,335,220)	$0	$0	($95,126)	$0	$0	$0	$0	($112,500)	($53,358)	($5,262)	($84,085)	($1,685,551)
d. Other (a)		($22,956)	($9,668)	($50,264)	($24,333)	($24,724)	($21,028)	($30,381)	($36,334)	($22,260)	($40,833)	$147,141	($18,902)	($154,542)
2. Plant-In-Service/Depreciation Base (b)	$426,051,646	$426,621,061	$426,682,881	$426,822,005	$426,726,879	$426,822,340	$426,839,542	$426,842,547	$426,908,694	$426,796,776	$426,846,015	$427,038,521	$427,118,948	
3a. Less: Accumulated Depreciation	$114,083,425	$113,801,837	$114,869,514	$115,896,677	$116,854,539	$117,907,137	$118,963,619	$120,010,824	$121,052,160	$121,995,014	$122,978,364	$124,198,082	$125,173,264	
4. CWIP Non-Interest Bearing	$2,298,671	$517,650	$588,721	$991,730	$1,120,910	$1,149,881	$1,320,294	$1,507,725	$1,551,070	$1,664,181	$1,721,226	$1,849,602	$1,774,599	
5. Net Investment (Lines 2 - 3 + 4)	$314,266,891	$313,336,874	$312,402,088	$311,917,058	$310,993,250	$310,065,084	$309,196,218	$308,339,449	$307,407,604	$306,465,942	$305,588,878	$304,690,041	$303,720,282	
6. Average Net Investment		$313,801,882	$312,869,481	$312,159,573	$311,455,154	$310,529,167	$309,630,651	$308,767,833	$307,873,526	$306,936,773	$306,027,410	$305,139,459	$304,205,162	
a. Average ITC Balance		$86,221,201	$85,877,403	$85,533,605	$85,189,807	$84,846,009	$84,502,211	$84,158,413	$83,814,615	$83,470,817	$83,127,019	$82,783,221	$82,439,423	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$1,890,153	$1,884,384	$1,879,848	$1,875,342	$1,869,608	$1,864,027	$1,825,630	$1,820,190	$1,814,516	$1,808,992	$1,803,587	$1,797,926	$22,134,202
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$375,512	$374,374	$373,486	$372,604	$371,473	$370,373	$369,610	$368,514	$367,371	$366,258	$365,169	$364,028	$4,438,773
8. Investment Expenses														
a. Depreciation (e)		$1,027,033	$1,027,790	$1,027,872	$1,027,766	$1,027,767	$1,027,954	$1,028,031	$1,028,114	$1,028,059	$1,027,986	$1,028,284	$1,028,614	$12,335,271
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$594,660
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($5,421,012)
9. Total System Recoverable Costs (Lines 7 & 8)		$2,890,502	$2,884,352	$2,879,010	$2,873,516	$2,866,652	$2,860,158	$2,821,076	$2,814,622	$2,807,750	$2,801,040	$2,794,844	$2,788,373	$34,081,894

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
41 - Manatee Temporary Heating System														
Distribution														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$1,417,015	$1,417,015	$1,417,015	$1,417,015	$1,417,015	$1,417,015	$1,417,015	$1,417,015	$1,417,015	$1,417,015	$1,417,015	$1,417,015	$1,417,015	
3a. Less: Accumulated Depreciation	$1,189,310	$1,189,310	$1,189,310	$1,189,310	$1,189,310	$1,189,310	$1,189,310	$1,189,310	$1,189,310	$1,189,310	$1,189,310	$1,189,310	$1,189,310	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	
6. Average Net Investment		$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$1,262	$1,262	$1,262	$1,262	$1,262	$1,262	$1,252	$1,252	$1,252	$1,252	$1,252	$1,252	$15,082
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$256	$256	$256	$256	$256	$256	$257	$257	$257	$257	$257	$257	$3,079
8. Investment Expenses														
a. Depreciation (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$1,518	$1,518	$1,518	$1,518	$1,518	$1,518	$1,508	$1,508	$1,508	$1,508	$1,508	$1,508	$18,161

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
41 - Manatee Temporary Heating System														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$36,256	$28	$431	$79	$4,439,770	$0	$43	$0	$0	$74	$0	$0	$4,476,682
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$453,549	$0	$863	$0	$0	$0	$0	$0	$454,412
2. Plant-In-Service/Depreciation Base (b)	$13,096,633	$13,132,888	$13,132,917	$13,133,348	$13,133,427	$17,573,197	$17,573,831	$17,573,875	$17,573,875	$17,573,875	$17,573,949	$17,573,949	$17,573,949	
3a. Less: Accumulated Depreciation	$4,246,609	$4,341,827	$4,437,249	$4,532,673	$4,628,098	$5,277,965	$5,474,293	$5,671,491	$5,867,826	$6,064,162	$6,260,498	$6,456,835	$6,653,173	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$8,850,024	$8,791,062	$8,695,667	$8,600,675	$8,505,329	$12,295,232	$12,099,539	$11,902,384	$11,706,048	$11,509,713	$11,313,451	$11,117,114	$10,920,776	
6. Average Net Investment		$8,820,543	$8,743,364	$8,648,171	$8,553,002	$10,400,280	$12,197,385	$12,000,961	$11,804,216	$11,607,881	$11,411,582	$11,215,282	$11,018,945	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$48,893	$48,465	$47,937	$47,410	$57,649	$67,611	$65,959	$64,878	$63,799	$62,720	$61,641	$60,562	$697,524
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$9,928	$9,842	$9,734	$9,627	$11,707	$13,729	$13,539	$13,318	$13,096	$12,875	$12,653	$12,432	$142,480
8. Investment Expenses														
a. Depreciation (e)		$95,218	$95,423	$95,424	$95,425	$196,318	$196,327	$196,335	$196,336	$196,336	$196,336	$196,337	$196,337	$1,952,151
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$154,039	$153,729	$153,095	$152,462	$265,674	$277,668	$275,834	$274,531	$273,230	$271,931	$270,631	$269,331	$2,792,155

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
41 - Manatee Temporary Heating System														
Peaking														
1. Investments														
a. Expenditures/Additions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant	$0	$19,549	$36	$0	$101	($4,439,156)	$0	$0	$0	$0	$0	$0	$0	($4,419,469)
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)	$0	$0	$0	$0	$0	($453,549)	$0	$0	$0	$0	$0	$0	$0	($453,549)
2. Plant-In-Service/Depreciation Base (b)	$4,419,469	$4,439,019	$4,439,055	$4,439,055	$4,439,156									
3a. Less: Accumulated Depreciation	$50,221	$150,886	$251,773	$352,660	$453,549	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$4,369,248	$4,288,133	$4,187,282	$4,086,395	$3,985,607	$0	$0	$0	$0	$0	$0	$0	$0	
6. Average Net Investment		$4,328,691	$4,237,708	$4,136,838	$4,036,001	$1,992,803	$0	$0	$0	$0	$0	$0	$0	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)	$0	$23,994	$23,490	$22,931	$22,372	$11,046	$0	$0	$0	$0	$0	$0	$0	$103,833
b. Debt Component (Line 6 x debt rate x 1/12) (d)(	$0	$4,872	$4,770	$4,656	$4,543	$2,243	$0	$0	$0	$0	$0	$0	$0	$21,085
8. Investment Expenses														
a. Depreciation (e)	$0	$100,665	$100,887	$100,888	$100,889	$0	$0	$0	$0	$0	$0	$0	$0	$403,328
b. Amortization (f)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)	$0	$129,531	$129,147	$128,475	$127,803	$13,289	$0	$0	$0	$0	$0	$0	$0	$528,245

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8A

JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
41 - Manatee Temporary Heating System														
Transmission														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	
3a. Less: Accumulated Depreciation	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
6. Average Net Investment		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8. Investment Expenses														
a. Depreciation (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES
JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
42 - Turkey Point Cooling Canal Monitoring Plan														
Base														
1. Investments														
a. Expenditures/Additions		$550,722	$350,772	$396,584	$1,096,833	($14,453,196)	$1,050,400	$959,988	($1,112,658)	$883,797	($5,540)	$186,136	($5,677,345)	($15,773,508)
b. Clearings to Plant		$714,322	$0	$0	$0	$0	$0	$0	$1,904,966	$4,781	$430,715	$13,138	$20,732,087	$23,800,010
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$40,096,965	$40,811,287	$40,811,287	$40,811,287	$40,811,287	$40,811,287	$40,811,287	$40,811,287	$42,716,253	$42,721,035	$43,151,750	$43,164,888	$63,896,975	
3a. Less: Accumulated Depreciation	$3,321,476	$3,427,236	$3,534,089	$3,640,942	$3,747,794	$3,854,647	$3,961,500	$4,068,352	$4,178,744	$4,292,683	$4,409,866	$4,530,433	$4,697,694	
4. CWIP Non-Interest Bearing	$16,168,005	$16,718,726	$17,069,499	$17,466,083	$18,562,916	$4,109,720	$5,160,120	$6,120,108	$5,007,449	$5,891,246	$5,885,706	$6,071,842	$394,497	
5. Net Investment (Lines 2 - 3 + 4)	$52,943,494	$54,102,777	$54,346,697	$54,636,429	$55,626,409	$41,066,360	$42,009,908	$42,863,042	$43,544,959	$44,319,597	$44,627,589	$44,706,297	$59,593,778	
6. Average Net Investment		$53,523,136	$54,224,737	$54,491,563	$55,131,419	$48,346,384	$41,538,134	$42,436,475	$43,204,001	$43,932,278	$44,473,593	$44,666,943	$52,150,038	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$296,682	$300,571	$302,050	$305,597	$267,987	$230,248	$233,238	$237,456	$241,459	$244,434	$245,497	$286,625	$3,191,842
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$60,246	$61,035	$61,336	$62,056	$54,419	$46,755	$47,877	$48,743	$49,564	$50,175	$50,393	$58,836	$651,435
8. Investment Expenses														
a. Depreciation (e)		$105,760	$106,853	$106,853	$106,853	$106,853	$106,853	$106,853	$110,391	$113,939	$117,184	$120,566	$167,262	$1,376,219
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$462,688	$468,459	$470,238	$474,505	$429,258	$383,856	$387,967	$396,590	$404,962	$411,793	$416,456	$512,722	$5,219,496

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
42 - Turkey Point Cooling Canal Monitoring Plan														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$14,859,266	$100,289	($593)	$2,720	($9,028)	$13,490	($9,802)	($14,956,343)	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)						$14,859,266	$14,959,555	$14,958,963	$14,961,683	$14,952,654	$14,966,144	$14,956,343		
3a. Less: Accumulated Depreciation						$14,426	$43,375	$72,421	$101,469	$130,511	$159,557	$188,607	$203,127	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$14,844,840	$14,916,180	$14,886,542	$14,860,214	$14,822,144	$14,806,587	$14,767,736	($203,127)	
6. Average Net Investment		$0	$0	$0	$0	$7,422,420	$14,880,510	$14,901,361	$14,873,378	$14,841,179	$14,814,366	$14,787,162	$7,282,305	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$0	$0	$0	$0	$41,143	$82,484	$81,900	$81,746	$81,569	$81,422	$81,273	$40,025	$571,562
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$0	$0	$0	$0	$8,355	$16,750	$16,812	$16,780	$16,744	$16,714	$16,683	$8,216	$117,052
8. Investment Expenses														
a. Depreciation (e)		$0	$0	$0	$0	$14,426	$28,949	$29,046	$29,048	$29,042	$29,046	$29,050	$14,520	$203,127
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$0	$0	$0	$0	$63,923	$128,182	$127,758	$127,575	$127,355	$127,182	$127,005	$62,761	$891,741

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8A

JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
44 - Martin Plant Barley Barber Swamp Iron Mitigation														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	
3a. Less: Accumulated Depreciation	$17,993	$18,190	$18,388	$18,585	$18,782	$18,979	$19,176	$19,373	$19,571	$19,768	$19,965	$20,162	$20,359	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$75,896	$75,699	$75,502	$75,305	$75,108	$74,910	$74,713	$74,516	$74,319	$74,122	$73,925	$73,727	$73,530	
6. Average Net Investment		$75,798	$75,601	$75,403	$75,206	$75,009	$74,812	$74,615	$74,418	$74,220	$74,023	$73,826	$73,629	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$420	$419	$418	$417	$416	$415	$410	$409	$408	$407	$406	$405	$4,949
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$85	$85	$85	$85	$84	$84	$84	$84	$84	$84	$83	$83	$1,010
8. Investment Expenses														
a. Depreciation (e)		$197	$197	$197	$197	$197	$197	$197	$197	$197	$197	$197	$197	$2,366
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$703	$701	$700	$699	$697	$696	$691	$690	$689	$688	$686	$685	$8,325

(a) Applicable to reserve salvage and removal cost

(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.

(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.

(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.

(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

(h) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.

Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
44 - Martin Plant Barley Barber Swamp Iron Mitigation														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	
3a. Less: Accumulated Depreciation	$13,574	$13,723	$13,871	$14,020	$14,169	$14,318	$14,466	$14,615	$14,764	$14,913	$15,061	$15,210	$15,359	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$57,255	$57,106	$56,958	$56,809	$56,660	$56,511	$56,363	$56,214	$56,065	$55,916	$55,768	$55,619	$55,470	
6. Average Net Investment		$57,181	$57,032	$56,883	$56,734	$56,586	$56,437	$56,288	$56,140	$55,991	$55,842	$55,693	$55,545	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$317	$316	$315	$314	$314	$313	$309	$309	$308	$307	$306	$305	$3,733
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$64	$64	$64	$64	$64	$64	$64	$63	$63	$63	$63	$63	$762
8. Investment Expenses														
a. Depreciation (e)		$149	$149	$149	$149	$149	$149	$149	$149	$149	$149	$149	$149	$1,785
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$530	$529	$528	$527	$526	$525	$522	$521	$520	$519	$518	$517	$6,280

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
45 - 800 MW Unit ESP														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$63,759	$63,759	$63,759	$63,759	$63,759	$63,759	$63,759	$63,759	$63,759	$63,759	$63,759	$63,759	$63,759	
3a. Less: Accumulated Depreciation	$16,482	$16,887	$17,292	$17,697	$18,102	$18,506	$18,911	$19,316	$19,721	$20,126	$20,531	$20,936	$21,340	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$47,276	$46,872	$46,467	$46,062	$45,657	$45,252	$44,847	$44,442	$44,038	$43,633	$43,228	$42,823	$42,418	
6. Average Net Investment		$47,074	$46,669	$46,264	$45,859	$45,455	$45,050	$44,645	$44,240	$43,835	$43,430	$43,025	$42,620	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$261	$259	$256	$254	$252	$250	$245	$243	$241	$239	$236	$234	$2,971
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$53	$53	$52	$52	$51	$51	$50	$50	$49	$49	$49	$48	$606
8. Investment Expenses														
a. Depreciation (e)		$405	$405	$405	$405	$405	$405	$405	$405	$405	$405	$405	$405	$4,858
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$719	$716	$713	$711	$708	$705	$701	$698	$695	$693	$690	$687	$8,436

(a) Applicable to reserve salvage and removal cost

(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.

(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.

(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.

(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

(h) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.

Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FORM: 42-8A

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
45 - 800 MW Unit ESP														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$404,851	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$404,851
c. Retirements		$0	$404,851	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$404,851
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$107,963,814	$107,963,814	$108,368,665	$108,369,392	$108,369,392	$108,369,392	$108,369,392	$108,369,392	$108,369,392	$108,369,392	$108,369,392	$108,369,392	$108,369,392	
3a. Less: Accumulated Depreciation	($65,627,065)	($65,197,468)	($64,362,179)	($63,930,791)	($63,499,404)	($63,068,016)	($62,636,628)	($62,205,241)	($61,773,853)	($61,342,466)	($60,911,078)	($60,479,690)	($60,048,303)	
4. CWIP Non-Interest Bearing	($378)	($378)	($378)	($378)	($378)	($378)	($378)							
5. Net Investment (Lines 2 - 3 + 4)	$173,590,500	$173,160,904	$172,730,466	$172,299,805	$171,868,418	$171,437,030	$171,005,643	$170,574,633	$170,143,245	$169,711,858	$169,280,470	$168,849,083	$168,417,695	
6. Average Net Investment		$173,375,702	$172,945,685	$172,515,135	$172,084,112	$171,652,724	$171,221,336	$170,790,138	$170,358,939	$169,927,552	$169,496,164	$169,064,776	$168,633,389	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$961,032	$958,648	$956,262	$953,872	$951,481	$949,090	$938,690	$936,320	$933,949	$931,578	$929,207	$926,836	$11,326,963
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$195,152	$194,668	$194,183	$193,698	$193,212	$192,727	$192,685	$192,199	$191,712	$191,226	$190,739	$190,252	$2,312,453
		0	0	0	0	0	0	0	0	0	0	0	0	0
8. Investment Expenses		0	0	0	0	0	0	0	0	0	0	0	0	0
a. Depreciation (e)		$429,597	$430,438	$431,388	$431,388	$431,388	$431,388	$431,388	$431,388	$431,388	$431,388	$431,388	$431,388	$5,173,911
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$1,585,780	$1,583,754	$1,581,832	$1,578,958	$1,576,081	$1,573,204	$1,562,763	$1,559,906	$1,557,049	$1,554,191	$1,551,333	$1,548,476	$18,813,326

(a) Applicable to reserve salvage and removal cost

(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.

(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.

(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.

(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

(h) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.

Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
47 - NPDES Permit Renewal Requirements														
Base														
1. Investments														
a. Expenditures/Additions	$0	$0	$0	$0	$0	$2,266	$135,188	$494,739	$464,995	($15,958)	$16,156	$15,414	$1,193,846	$2,306,647
b. Clearings to Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)	$0	$0	$0	$0	$0	$0	($0)	($1)	($1)	$0	$0	($0)	($1)	($3)
2. Plant-In-Service/Depreciation Base (b)														
3a. Less: Accumulated Depreciation							($0)	($1)	($1)	($1)	($1)	($1)	($3)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$2,266	$173,192	$667,931	$1,132,926	$1,116,968	$1,133,125	$1,148,539	$2,342,385	
5. Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$2,266	$173,193	$667,932	$1,132,927	$1,116,970	$1,133,126	$1,148,540	$2,342,388	
6. Average Net Investment		$0	$0	$0	$0	$1,133	$87,729	$420,562	$900,430	$1,124,949	$1,125,048	$1,140,833	$1,745,464	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$0	$0	$0	$0	$6	$486	$2,311	$4,949	$6,183	$6,183	$6,270	$9,593	$35,983
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$0	$0	$0	$0	$1	$99	$474	$1,016	$1,269	$1,269	$1,287	$1,969	$7,385
8. Investment Expenses														
a. Depreciation (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$0	$0	$0	$0	$8	$585	$2,786	$5,965	$7,452	$7,453	$7,557	$11,563	$43,368

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8A

JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
50 - Steam Electric Effluent Guidelines Revised Rules														
Base														
1. Investments														
a. Expenditures/Additions	$0	$0	$30,395	$32,458	$81,005	$66,088	$76,833	$28,563	$38,794	$124,988	$32,077	$51,000	$118,719	$680,920
b. Clearings to Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)														
3a. Less: Accumulated Depreciation														
4. CWIP Non-Interest Bearing	$983,131	$983,131	$1,013,526	$1,045,984	$1,126,989	$1,193,077	$1,269,910	$1,298,472	$1,337,267	$1,462,255	$1,494,332	$1,545,332	$1,664,051	
5. Net Investment (Lines 2 - 3 + 4)	$983,131	$983,131	$1,013,526	$1,045,984	$1,126,989	$1,193,077	$1,269,910	$1,298,472	$1,337,267	$1,462,255	$1,494,332	$1,545,332	$1,664,051	
6. Average Net Investment		$983,131	$998,328	$1,029,755	$1,086,486	$1,160,033	$1,231,493	$1,284,191	$1,317,870	$1,399,761	$1,478,293	$1,519,832	$1,604,691	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$5,450	$5,534	$5,708	$6,022	$6,430	$6,826	$7,058	$7,243	$7,693	$8,125	$8,353	$8,820	$83,263
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$1,107	$1,124	$1,159	$1,223	$1,306	$1,386	$1,449	$1,487	$1,579	$1,668	$1,715	$1,810	$17,012
8. Investment Expenses														
a. Depreciation (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$6,556	$6,658	$6,867	$7,245	$7,736	$8,212	$8,507	$8,730	$9,273	$9,793	$10,068	$10,630	$100,275

(a) Applicable to reserve salvage and removal cost

(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.

(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.

(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.

(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
54 - Coal Combustion Residuals														
Base														
1. Investments														
a. Expenditures/Additions		$3,516,164	($2,840,848)	$1,724,261	$1,142,026	$1,361,035	($33,962,298)	$835,515	$684,800	$585,752	$1,226,178	$335,663	($28,234,940)	($53,626,692)
b. Clearings to Plant		$0	$0	$0	$0	$0	$34,895,696	$0	$0	$0	$0	$0	$0	$34,895,696
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$46,922,718	$46,922,718	$46,922,718	$46,398,629	$46,398,629	$46,398,629	$81,294,324	$81,294,324	$81,294,324	$81,294,324	$81,294,324	$81,294,324	$109,696,378	
3a. Less: Accumulated Depreciation	$1,871,389	$1,979,044	$2,086,698	$2,194,352	$2,302,006	$2,409,661	$2,557,881	$2,746,668	$2,935,455	$3,124,242	$3,313,028	$3,501,815	$3,719,947	
3b. Less: Capital Recovery Unamortized Balance	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	
4. CWIP Non-Interest Bearing	$53,626,692	$57,142,856	$54,302,008	$56,026,269	$57,168,294	$58,529,330	$24,567,032	$25,402,547	$26,087,347	$26,673,099	$27,899,277	$28,234,940	($0)	
5. Net Investment (Lines 2 - 3 + 4)	$98,733,270	$102,141,780	$99,193,278	$100,285,795	$101,320,167	$102,573,548	$103,358,725	$104,005,453	$104,501,466	$104,898,432	$105,935,823	$106,082,699	$106,031,681	
6. Average Net Investment		$100,437,525	$100,667,529	$99,739,537	$100,802,981	$101,946,857	$102,966,137	$103,682,089	$104,253,460	$104,699,949	$105,417,127	$106,009,261	$106,057,190	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$556,731	$558,006	$552,862	$558,757	$565,097	$570,747	$569,853	$572,993	$575,447	$579,389	$582,644	$582,907	$6,825,435
b. Debt Component (Line 6 x debt rate x 1/12) (d)(		$113,052	$113,311	$112,267	$113,464	$114,751	$115,899	$116,974	$117,619	$118,122	$118,932	$119,600	$119,654	$1,393,645
8. Investment Expenses														
a. Depreciation (e)		$107,654	$107,654	$107,654	$107,654	$107,654	$148,221	$188,787	$188,787	$188,787	$188,787	$188,787	$218,132	$1,848,558
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$777,438	$778,972	$772,783	$779,875	$787,503	$834,867	$875,614	$879,399	$882,357	$887,108	$891,030	$920,693	$10,067,637

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
123-The Protected Species Project														
Intermediate														
1. Investments														
a. Expenditures/Additions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,012	$3,012
b. Clearings to Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)														
3a. Less: Accumulated Depreciation														
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,012	
5. Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,012	
6. Average Net Investment													$1,506	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$8	$8
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2	$2
8. Investment Expenses														
a. Depreciation (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10	$10

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 69-72.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 69-72.
(f) Applicable amortization period(s). See Form 42-8A, pages 69-72.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1 Working Capital Dr (Cr)														
a. 158.100 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
b. 158.200 Allowances Withheld	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
c. 182.300 Other Regulatory Assets-Losses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
d 254.900Other Regulatory Liabilities-Gains	($242)	($235)	($228)	($220)	($220)	($227)	($240)	($235)	($235)	($166)	($166)	($166)	($144)	
2 Total Working Capital	($242)	($235)	($228)	($220)	($220)	($227)	($240)	($235)	($235)	($166)	($166)	($166)	($144)	
3 Average Net Working Capital Balance		($238)	($231)	($224)	($220)	($223)	($233)	($237)	($235)	($201)	($166)	($166)	($155)	
4 Return on Average Net Working Capital Balance														
a. Equity Component grossed up for taxes	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	
b. Debt Component	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	
5. Total Return Component	($2)	($2)	($2)	($1)	($1)	($1)	($2)	($2)	($2)	($1)	($1)	($1)	($1)	($17)
6. Expense Dr (Cr)														
a. 411.800 Gains from Dispositions of Allowances	($44)	($7)	($7)	($7)			($28)			($68)			($22)	
b. 411.900 Losses from Dispositions of Allowances	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
c. 509.000 Allowance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
7. Net Expense (Lines 6a+6b+6c)	($44)	($7)	($7)	($7)			($28)			($68)			($22)	($141)
8. Total System Recoverable Expenses (Lines 5+7)	($46)	($9)	($9)	($9)	($1)	($1)	($30)	($2)	($2)	($70)	($1)	($1)	($23)	

(a) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.

(b) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2020 Earning Surveillance Report.

(c) Line 8a times Line 9

(d) Line 8b times Line 10

(e) Line 5 is reported on Capital Schedule

(f) Line 7 is reported on O&M Schedule

2020 Depreciation Schedule **FORM 42-8A**

Project	Function	Unit	Utility	DEPR RATE	12/1/2019	12/1/2020
002-LOW NOX BURNER TECHNOLOGY	02 - Steam Generation Plant	Turkey Pt U1	31200	0.00%	0	-
002-LOW NOX BURNER TECHNOLOGY Total					**0**	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee Comm	31200	7.62%	65,605	65,605
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee U1	31100	1.74%	56,430	56,430
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee U1	31200	4.64%	424,505	424,505
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee U2	31100	1.83%	56,333	56,333
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee U2	31200	4.99%	468,728	468,728
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin Comm	31200	4.45%		-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin Comm	31650	5-Year		-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin Comm	31670	7-Year		-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin U1	31100	2.68%		-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin U1	31200	4.53%		-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin U2	31100	2.39%		-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin U2	31200	4.64%		-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Scherer U4	31200	2.79%	515,653	515,653
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	SJRPP - Comm	31100	1.09%		-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	SJRPP - Comm	31200	1.44%		-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Turkey Pt Comm	31100	0.00%		-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Turkey Pt Comm	31200	0.00%		-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Turkey Pt U1	31200	0.00%		-
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtLauderdale Comm	34100	2.20%		-
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtLauderdale Comm	34500	1.60%		-
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtLauderdale GTs	34300	8.25%	10,225	10,225
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtLauderdale U4	34300	4.11%		-
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtLauderdale U5	34300	5.00%		-
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtMyers U2	34300	3.46%	365,000	365,000
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtMyers U3 SC Peaker	34100	3.38%	6,098	6,098
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtMyers U3 SC Peaker	34300	4.54%	141,021	141,021
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Manatee U3	34300	3.35%	87,691	87,691
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Martin U3	34300	4.49%	615,469	615,469
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Martin U4	34300	3.92%	598,036	598,036
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Martin U8	34300	3.37%	13,693	13,693
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Sanford U4	34300	4.00%	310,021	310,021
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Sanford U5	34300	4.12%	273,035	273,035
003-CONTINUOUS EMISSION MONITORING Total					**4,007,544**	**4,007,544**
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Manatee Comm	31100	3.17%	3,111,263	3,111,263
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Manatee Comm	31200	7.62%	174,543	174,543
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Manatee U1	31200	4.64%	104,845	104,845
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Manatee U2	31200	4.99%	127,429	127,429
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Martin Comm	31100	2.52%	198,665	65,093
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Martin Comm	31200	4.45%		-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Martin U1	31100	2.68%		-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Martin U2	31100	2.39%		-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	SJRPP - Comm	31100	1.09%		-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	SJRPP - Comm	31200	1.44%		-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Turkey Pt Comm	31100	0.00%		-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	FtLauderdale Comm	34200	3.09%	898,111	898,111
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	FtLauderdale GTs	34200	4.73%	584,290	584,290
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	FtMyers GTs	34200	7.84%	133,479	133,479
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	FtMyers U3 SC Peaker	34200	3.58%	18,616	18,616
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	Martin Comm	34200	2.42%	455,941	455,941
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	PtEverglades GTs	34200	0.00%		-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	08 - General Plant	General Plant	39000	1.50%	5,837,840	5,837,840
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS Total					**11,645,022**	**11,511,450**
007-RELOCATE TURBINE LUBE OIL PIPING	03 - Nuclear Generation Plant	StLucie U1	32300	5.11%	31,030	31,030
007-RELOCATE TURBINE LUBE OIL PIPING Total					**31,030**	**31,030**

Project	Function	Unit	Utility	DEPR RATE	12/1/2019	12/1/2020
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Manatee Comm	31100	3.17%	46,882	46,882
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Manatee Comm	31670	7-Year		-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Martin Comm	31600	3.79%		-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Martin Comm	31650	5-Year	227,249	227,249
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Martin Comm	31670	7-Year	298,813	253,877
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Turkey Pt Comm	31100	0.00%		-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	CapeCanaveral U1CC	34100	2.69%		128,024
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	FtLauderdale Comm	34100	2.20%	358,636	358,605
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	FtMyers Comm	34650	5-Year		-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	PtEverglades U5	34100	2.64%	22,550	22,550
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	Riviera Comm	34650	20.00%		-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	Sanford Comm	34100	2.40%	15,922	15,922
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	07 - Distribution Plant - Electric	Mass Distribution Plant	36670	2.00%	2,995	2,995
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	08 - General Plant	General Plant	39000	1.50%	4,413	4,413
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	08 - General Plant	General Plant	39190	3-Year		-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT Total					**977,460**	**1,060,517**
010-REROUTE STORMWATER RUNOFF	03 - Nuclear Generation Plant	StLucie Comm	32100	2.25%	117,794	117,794
010-REROUTE STORMWATER RUNOFF Total					**117,794**	**117,794**
012-SCHERER DISCHARGE PIPELINE	02 - Steam Generation Plant	Scherer Comm	31100	1.51%	524,873	524,873
012-SCHERER DISCHARGE PIPELINE	02 - Steam Generation Plant	Scherer Comm	31200	2.23%	328,762	328,762
012-SCHERER DISCHARGE PIPELINE	02 - Steam Generation Plant	Scherer Comm	31400	2.08%	689	689
012-SCHERER DISCHARGE PIPELINE Total					**854,324**	**854,324**
020-WASTEWATER/STORMWATER DISCH ELIMINATION	02 - Steam Generation Plant	Martin U1	31200	4.53%		-
020-WASTEWATER/STORMWATER DISCH ELIMINATION	02 - Steam Generation Plant	Martin U2	31200	4.64%		-
020-WASTEWATER/STORMWATER DISCH ELIMINATION Total						**-**
021-ST.LUCIE TURTLE NETS	03 - Nuclear Generation Plant	StLucie Comm	32100	2.25%	6,909,559	6,909,559
021-ST.LUCIE TURTLE NETS Total					**6,909,559**	**6,909,559**
022-PIPELINE INTEGRITY MANAGEMENT	02 - Steam Generation Plant	Manatee Comm	31100	3.17%	601,217	601,217
022-PIPELINE INTEGRITY MANAGEMENT	02 - Steam Generation Plant	Martin Comm	31100	2.52%	2,271,574	2,271,574
022-PIPELINE INTEGRITY MANAGEMENT Total					**2,872,791**	**2,872,791**
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee Comm	31100	3.17%	1,243,306	1,243,306
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee Comm	31200	7.62%	33,272	33,272
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee Comm	31500	2.34%	26,325	26,325
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee U1	31200	4.64%	45,750	45,750
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee U2	31200	4.99%	37,431	37,431
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Martin Comm	31100	2.52%	37,158	37,158
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Martin Comm	31500	3.57%		-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Turkey Pt Comm	31100	0.00%		-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	StLucie U1	32300	5.11%	712,225	712,225
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	StLucie U1	32400	3.20%	745,335	745,335
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	StLucie U2	32300	3.86%	552,390	552,390
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	Turkey Pt Comm	32100	3.13%	990,124	990,124
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	Turkey Pt Comm	32570	7-Year	245,362	245,362
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtLauderdale Comm	34100	2.20%	189,219	189,219
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtLauderdale Comm	34200	3.09%	1,480,169	1,480,169
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtLauderdale Comm	34300	5.20%	28,250	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtLauderdale GTs	34100	4.18%		-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtLauderdale GTs	34200	4.73%	513,250	513,250
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtMyers GTs	34100	7.40%	98,715	98,715
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtMyers GTs	34200	7.84%	629,983	629,983
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtMyers GTs	34500	7.77%	12,430	12,430
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtMyers U2	34300	3.46%	49,727	49,727
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtMyers U3 SC Peaker	34500	3.40%	12,430	12,430
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Martin Comm	34100	2.24%	523,498	523,498
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Martin U8	34200	2.70%	84,868	84,868
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	PtEverglades Comm	34200	2.90%	2,728,283	2,728,283
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	PtEverglades GTs	34100	0.00%		-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	PtEverglades GTs	34200	0.00%		-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	PtEverglades GTs	34500	0.00%		-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	PtEverglades U5	34200	2.90%		286,434
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Sanford Comm	34100	2.40%	288,383	288,383
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electric	Radial	35200	1.70%	6,946	6,946
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electric	Transmission Plant - Electric	35200	1.70%	1,142,640	1,142,640
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electric	Transmission Plant - Electric	35300	2.04%	2,903,187	2,903,037
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electric	Transmission Plant - Electric	35800	1.87%	65,655	65,655
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	07 - Distribution Plant - Electric	Mass Distribution Plant	36100	1.75%	3,336,463	3,458,511
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	07 - Distribution Plant - Electric	Mass Distribution Plant	36670	2.00%	70,499	70,499
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	08 - General Plant	General Plant	39000	1.50%	146,691	146,691
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES Total					**18,979,966**	**19,360,047**

Project	Function	Unit	Utility	DEPR RATE	12/1/2019	12/1/2020
024-GAS REBURN	02 - Steam Generation Plant	Manatee U1	31200	4.64%	16,470,024	16,470,024
024-GAS REBURN	02 - Steam Generation Plant	Manatee U2	31200	4.99%	15,393,694	15,393,694
024-GAS REBURN Total					**31,863,719**	**31,863,719**
026-UST REPLACEMENT/REMOVAL	08 - General Plant	General Plant	39000	1.50%	115,447	115,447
026-UST REPLACEMENT/REMOVAL Total					**115,447**	**115,447**
028-CWA 316B PHASE II RULE	05 - Other Generation Plant	CapeCanaveral Comm	34100	2.69%	771,310	771,310
028-CWA 316B PHASE II RULE Total					**771,310**	**771,310**
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee Comm	31100	3.17%	102,052	102,052
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee U1	31200	4.64%	20,059,060	20,059,060
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee U1	31400	4.03%	7,240,124	7,240,124
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee U2	31200	4.99%	20,457,354	20,457,354
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee U2	31400	3.72%	7,905,907	7,905,907
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin Comm	31200	4.45%		-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin Comm	31400	3.48%		-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin U1	31200	4.53%		-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin U1	31400	3.35%		-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin U2	31200	4.64%		-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin U2	31400	4.79%		-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer Comm U3&4	31200	2.32%	3,179,403	5,419,967
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31100	2.30%	82,366,984	82,366,984
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31200	2.79%	254,475,936	254,475,936
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31400	1.89%	(94,224)	(94,224)
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31500	2.49%	19,615,426	19,615,426
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31600	1.88%	399,586	399,586
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31670	7-Year	268	-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	SJRPP - Comm	31200	1.44%		-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	SJRPP - Comm	31500	1.30%		-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	SJRPP - Comm	31600	1.31%		-
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	FtLauderdale GTs	34300	8.25%	110,242	110,242
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	FtMyers GTs	34300	8.22%	57,855	57,855
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	Martin Comm	34100	2.24%	699,143	699,143
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	Martin Comm	34300	2.56%	244,343	244,343
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	Martin Comm	34500	2.04%	292,499	292,499
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	PtEverglades GTs	34300	0.00%		-
031-CLEAN AIR INTERSTATE RULE-CAIR	07 - Distribution Plant - Electric	Mass Distribution Plant	36500	2.57%	1,313	1,313
031-CLEAN AIR INTERSTATE RULE-CAIR Total					**417,113,272**	**419,353,567**
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	Scherer Comm U3&4	31200	2.32%	(1,234,037)	(1,234,037)
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	Scherer U4	31100	2.30%		-
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	Scherer U4	31200	2.79%	110,494,775	110,565,526
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	Scherer U4	31500	2.49%		-
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	SJRPP - Comm	31200	1.44%		-
033-CLEAN AIR MERCURY RULE-CAMR Total					**109,260,738**	**109,331,489**
035-MARTIN PLANT DRINKING WATER COMP	02 - Steam Generation Plant	Martin Comm	31100	2.52%	235,391	-
035-MARTIN PLANT DRINKING WATER COMP Total					**235,391**	**-**
036-LOW LEV RADI WSTE-LLW	03 - Nuclear Generation Plant	StLucie Comm	32100	2.25%	7,601,405	7,601,405
036-LOW LEV RADI WSTE-LLW	03 - Nuclear Generation Plant	Turkey Pt Comm	32100	3.13%	9,855,399	9,855,399
036-LOW LEV RADI WSTE-LLW Total					**17,456,804**	**17,456,804**
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34000	0.00%	255,507	255,507
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34100	3.49%	5,263,916	5,263,916
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34300	3.36%	115,292,583	115,295,697
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34500	3.65%	26,746,246	26,746,246
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34630	3-Year	15,749	7,279
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34650	5-Year	51,031	24,247
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34670	7-Year	182,866	154,715
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	TransGeneratorLead	35300	2.04%	308,244	308,244
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35200	1.70%	7,427	7,427
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35300	2.04%	695,782	687,149
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35310	2.64%	1,695,869	1,695,869
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35500	2.32%	394,418	394,418
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35600	2.38%	191,358	191,358
037-DE SOTO SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36100	1.75%	540,994	540,994
037-DE SOTO SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36200	1.90%	1,890,938	1,890,938
037-DE SOTO SOLAR PROJECT	08 - General Plant	General Plant	39220	10.00%	28,426	28,426
037-DE SOTO SOLAR PROJECT	08 - General Plant	General Plant	39720	7-Year		-
037-DE SOTO SOLAR PROJECT Total					**153,561,354**	**153,492,429**

Project	Function	Unit	Utility	DEPR RATE	12/1/2019	12/1/2020
038-SPACE COAST SOLAR PROJECT	01 - Intangible Plant	Intangible Plant	30300	various	6,359,027	6,359,027
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast Solar	34100	3.45%	3,893,263	3,893,263
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast Solar	34300	3.30%	51,550,587	51,550,587
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast Solar	34500	3.51%	6,126,699	6,126,699
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast Solar	34630	3-Year		1,105
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast Solar	34650	5-Year	35,202	-
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast Solar	34670	7-Year		-
038-SPACE COAST SOLAR PROJECT	06 - Transmission Plant - Electric	TransGeneratorLead	35300	2.04%	789,138	789,138
038-SPACE COAST SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35300	2.04%	139,391	139,391
038-SPACE COAST SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35310	2.64%	1,328,699	1,328,699
038-SPACE COAST SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36100	1.75%	274,858	274,858
038-SPACE COAST SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36200	1.90%	62,689	62,689
038-SPACE COAST SOLAR PROJECT	08 - General Plant	General Plant	39220	10.00%	31,858	31,858
038-SPACE COAST SOLAR PROJECT	08 - General Plant	General Plant	39720	7-Year		-
038-SPACE COAST SOLAR PROJECT Total					**70,591,411**	**70,557,314**
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34000	0.00%	216,844	216,844
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34100	2.99%	20,756,023	20,798,049
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34300	2.88%	398,862,026	399,689,021
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34500	2.99%	4,122,852	4,177,638
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34600	2.85%	56,448	56,448
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34650	5-Year		-
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34670	7-Year	138,981	150,046
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin U8	34300	3.37%	423,126	423,126
039-MARTIN SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35500	2.32%	603,692	603,692
039-MARTIN SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35600	2.38%	364,159	364,159
039-MARTIN SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36500	2.57%		-
039-MARTIN SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36660	1.42%	94,476	94,476
039-MARTIN SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36760	1.96%	2,728	2,728
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	39220	10.00%	121,101	121,101
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	39240	2.63%	332,682	332,682
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	39290	4.99%	88,938	88,938
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	39420	7-Year		-
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	39720	7-Year		-
039-MARTIN SOLAR PROJECT Total					**426,184,075**	**427,118,948**
041-PRV MANATEE HEATING SYSTEM	05 - Other Generation Plant	CapeCanaveral Comm	34300	0.00%	4,042,459	4,042,459
041-PRV MANATEE HEATING SYSTEM	05 - Other Generation Plant	Dania Beach EC U7	34300	44 mos.	7,891,910	7,927,943
041-PRV MANATEE HEATING SYSTEM	05 - Other Generation Plant	FtMyers U2	34300	3.46%	5,581,733	5,603,547
041-PRV MANATEE HEATING SYSTEM	06 - Transmission Plant - Electric	Transmission Plant - Electric	35300	various	276,404	276,404
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36100	various	73,267	73,267
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36200	various	471,542	471,542
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36410	various	137,247	137,247
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36420	various	36,431	36,431
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36500	various	307,599	307,599
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36660	various	221,326	221,326
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36760	various	168,995	168,995
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36910	various	607	607
041-PRV MANATEE HEATING SYSTEM Total					**19,209,521**	**19,267,368**
042-PTN COOLING CANAL MONITORING SYS	03 - Nuclear Generation Plant	Turkey Pt Comm	32100	3.13%	39,915,222	62,314,631
042-PTN COOLING CANAL MONITORING SYS	03 - Nuclear Generation Plant	Turkey Pt Comm	32500	3.67%	181,743	1,037,522
042-PTN COOLING CANAL MONITORING SYS	03 - Nuclear Generation Plant	Turkey Pt Comm	32550	5-Year		544,822
042-PTN COOLING CANAL MONITORING SYS Total					**40,096,965**	**63,896,975**
044-Barley Barber Swamp Iron Mitiga	02 - Steam Generation Plant	Martin Comm	31100	2.52%	164,719	164,719
044-Barley Barber Swamp Iron Mitiga Total					**164,719**	**164,719**
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee Comm	31200	7.62%	153,660	153,660
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U1	31200	4.64%	44,854,496	44,485,716
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U1	31500	4.11%	4,524,074	4,524,074
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U1	31600	3.91%	1,021,918	1,021,918
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U2	31200	4.99%	51,505,899	52,279,530
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U2	31500	4.48%	4,793,798	4,793,798
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U2	31600	4.79%	1,174,454	1,174,454
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U1	31200	4.53%		-
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U1	31500	3.12%		-
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U1	31600	3.81%		-
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U2	31200	4.64%		-
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U2	31500	3.56%		-
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U2	31600	4.31%		-
045-800 MW UNIT ESP PROJECT Total					**108,028,300**	**108,433,151**
047-NPDES Permit Renewal Requirement	03 - Nuclear Generation Plant	StLucie Comm	32300	7.22%		-
047-NPDES Permit Renewal Requirement Total						**-**
054-Coal Combustion Residuals	02 - Steam Generation Plant	Scherer Comm	31100	1.51%	208,650	208,650
054-Coal Combustion Residuals	02 - Steam Generation Plant	Scherer Comm U3&4	31200	2.32%		18,751,871
054-Coal Combustion Residuals	02 - Steam Generation Plant	Scherer U4	31200	2.79%	46,189,978	90,735,857
054-Coal Combustion Residuals	02 - Steam Generation Plant	SJRPP - Comm	31100	1.09%		-
054-Coal Combustion Residuals Total					**46,398,629**	**109,696,378**
Grand Total					**1,487,447,141**	**1,578,244,673**

ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE FINAL TRUE-UP AMOUNT FOR THE PERIOD

FORM 42-9A

FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES

Equity @ 10.55%

CAPITAL STRUCTURE AND COST RATES PER MAY 2019 EARNINGS SURVEILLANCE REPORT

	ADJUSTED RETAIL	RATIO	MIDPOINT COST RATES	WEIGHTED COST	PRE-TAX WEIGHTED COST
LONG_TERM_DEBT	10,490,880,245	28.119%	4.44%	1.25%	1.25%
SHORT_TERM_DEBT	669,988,433	1.796%	3.62%	0.06%	0.06%
PREFERRED_STOCK	0	0.000%	0.00%	0.00%	0.00%
CUSTOMER_DEPOSITS	403,097,747	1.080%	2.11%	0.02%	0.02%
COMMON_EQUITY	17,554,936,062	47.053%	10.55%	4.96%	6.65%
DEFERRED_INCOME_TAX	7,870,776,333	21.096%	0.00%	0.00%	0.00%
INVESTMENT_TAX_CREDITS					
ZERO COST	0	0.000%	0.00%	0.00%	0.00%
WEIGHTED COST	319,453,350	0.856%	8.26%	0.07%	0.09%
TOTAL	$37,309,132,171	100.00%		6.37%	8.08%

CALCULATION OF THE WEIGHTED COST FOR CONVERTIBLE INVESTMENT TAX CREDITS (C-ITC) (a)

	ADJUSTED RETAIL	RATIO	COST RATE	WEIGHTED COST	PRE TAX COST
LONG TERM DEBT	$10,490,880,245	37.41%	4.441%	1.661%	1.661%
PREFERRED STOCK	0	0.00%	0.000%	0.000%	0.000%
COMMON EQUITY	17,554,936,062	62.59%	10.550%	6.604%	8.846%
TOTAL	$28,045,816,308	100.00%		8.265%	10.507%
RATIO					

DEBT COMPONENTS:	
LONG TERM DEBT	1.2488%
SHORT TERM DEBT	0.0649%
CUSTOMER DEPOSITS	0.0228%
TAX CREDITS -WEIGHTED	0.0142%
TOTAL DEBT	**1.3507%**
EQUITY COMPONENTS:	
PREFERRED STOCK	0.0000%
COMMON EQUITY	4.9641%
TAX CREDITS -WEIGHTED	0.0565%
TOTAL EQUITY	**5.0206%**
TOTAL	6.3713%
PRE-TAX EQUITY	6.7251%
PRE-TAX TOTAL	8.0758%

Note:

(a) This capital structure applies only to Convertible Investment Tax Credit (C-ITC)

ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE FINAL TRUE-UP AMOUNT FOR THE PERIOD

FORM 42-9A

FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES

Equity @ 10.55%

CAPITAL STRUCTURE AND COST RATES PER MAY 2020 EARNINGS SURVEILLANCE REPORT

	ADJUSTED RETAIL	RATIO	MIDPOINT COST RATES	WEIGHTED COST	PRE-TAX WEIGHTED COST
LONG_TERM_DEBT	12,539,092,665	30.643%	4.17%	1.28%	1.28%
SHORT_TERM_DEBT	462,827,285	1.131%	3.16%	0.04%	0.04%
PREFERRED_STOCK	0	0.000%	0.00%	0.00%	0.00%
CUSTOMER_DEPOSITS	420,293,246	1.027%	2.12%	0.02%	0.02%
COMMON_EQUITY	19,050,189,760	46.554%	10.55%	4.91%	6.51%
DEFERRED_INCOME_TAX	8,019,547,167	19.598%	0.00%	0.00%	0.00%
INVESTMENT_TAX_CREDITS					
ZERO COST	0	0.000%	0.00%	0.00%	0.00%
WEIGHTED COST	428,551,760	1.047%	8.02%	0.08%	0.11%
TOTAL	$40,920,501,883	100.00%		6.33%	7.95%

CALCULATION OF THE WEIGHTED COST FOR CONVERTIBLE INVESTMENT TAX CREDITS (C-ITC) (a)

	ADJUSTED RETAIL	RATIO	COST RATE	WEIGHTED COST	PRE TAX COST
LONG TERM DEBT	$12,539,092,665	39.69%	4.174%	1.657%	1.657%
PREFERRED STOCK	0	0.00%	0.000%	0.000%	0.000%
COMMON EQUITY	19,050,189,760	60.31%	10.550%	6.362%	8.429%
TOTAL	$31,589,282,425	100.00%		8.019%	10.086%
RATIO					

DEBT COMPONENTS:	
LONG TERM DEBT	1.2789%
SHORT TERM DEBT	0.0357%
CUSTOMER DEPOSITS	0.0218%
TAX CREDITS -WEIGHTED	0.0174%
TOTAL DEBT	**1.3538%**
EQUITY COMPONENTS:	
PREFERRED STOCK	0.0000%
COMMON EQUITY	4.9115%
TAX CREDITS -WEIGHTED	0.0666%
TOTAL EQUITY	**4.9781%**
TOTAL	6.3319%
PRE-TAX EQUITY	6.5954%
PRE-TAX TOTAL	7.9492%

Note:

(a) This capital structure applies only to Convertible Investment Tax Credit (C-ITC)

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Calculation of the Actual/Estimated True-Up Amount for the Period

January 2021 through December 2021

(1)	(2)
	2021
1. Over/(Under) Recovery for the Current Period (a)	$2,734,434
2. Interest Provision (b)	$13,943
3. Sum of Current Period Adjustments (c)	$0
4. Actual/Estimated True-Up to be Refunded/(Recovered)	$2,748,378

Notes:

(a) Form 2E, Line 5

(b) Form 2E, Line 6

(c) Form 2E, Line 11

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Calculation of the Actual/Estimated True-Up Amount for the Period

Form 42-2E

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
1. Clause Revenues (net of Revenue Taxes)	$11,121,867	$10,765,699	$11,299,742	$12,083,753	$13,749,434	$14,198,135	$15,280,541	$15,710,638	$15,282,775	$13,841,721	$12,305,439	$11,429,445	$157,069,189
2. True-Up Provision - Prior Period (e)	$1,570,977	$1,570,977	$1,570,977	$1,570,977	$1,570,977	$1,570,977	$1,570,977	$1,570,977	$1,570,977	$1,570,977	$1,570,977	$1,570,977	$18,851,728
3. Clause Revenues Applicable to Period (Lines 1 + 2)	12,692,845	12,336,676	12,870,719	13,654,730	15,320,412	15,769,113	16,851,518	17,281,615	16,853,752	15,412,698	13,876,417	13,000,422	$175,920,917
4. Jurisdictional Revenue Requirements													
a. O&M Activities (a)	$2,079,525	$2,074,644	$1,966,305	$2,031,992	$2,286,979	$2,179,835	$2,036,462	$2,301,172	$1,829,757	$2,017,755	$2,006,595	$2,815,463	$25,626,483
b. Capital Projects (b)	$12,395,177	$12,379,622	$12,355,601	$12,335,920	$12,311,923	$12,292,104	$12,276,351	$12,268,045	$12,259,830	$12,245,601	$12,228,188	$12,211,638	$147,559,999
c. Total Jurisdictional Revenue Requirements (Lines 4a + 4b)	$14,474,702	$14,454,266	$14,321,905	$14,367,911	$14,598,902	$14,471,938	$14,312,813	$14,569,218	$14,089,587	$14,263,356	$14,234,783	$15,027,102	$173,186,483
5.Over/(Under) Recovery (Lines 3 - 4c)	($1,781,857)	($2,117,590)	($1,451,186)	($713,181)	$721,510	$1,297,174	$2,538,705	$2,712,397	$2,764,165	$1,149,342	($358,366)	($2,026,679)	$2,734,434
6.Interest Provision (c)	$2,255	$2,006	$2,080	$1,673	$951	$673	$684	$720	$758	$771	$732	$640	$13,943
7.Beginning Balance True-Up & Interest Provision	$18,851,728	$15,501,148	$11,814,587	$8,794,504	$6,512,019	$5,663,502	$5,390,371	$6,358,784	$7,500,923	$8,694,869	$8,274,006	$6,345,394	$18,851,728
a. Deferred True-Up - Beginning of Period (d)(f)	$14,657,306	$14,657,306	$14,657,306	$14,657,306	$14,657,306	$14,657,306	$14,657,306	$14,657,306	$14,657,306	$14,657,306	$14,657,306	$14,657,306	
8.True-Up Collected/(Refunded) (see Line 2)	($1,570,977)	($1,570,977)	($1,570,977)	($1,570,977)	($1,570,977)	($1,570,977)	($1,570,977)	($1,570,977)	($1,570,977)	($1,570,977)	($1,570,977)	($1,570,977)	($18,851,728)
9.End of Period Total True-Up (Lines 5+6+7+7a+8)	$30,158,455	$26,471,893	$23,451,810	$21,169,325	$20,320,808	$20,047,678	$21,016,090	$22,158,230	$23,352,176	$22,931,312	$21,002,701	$17,405,684	$2,748,378
10.Adjustment to Period True-Up Including Interest	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11.End of Period Total True-Up (Lines 9 + 10)	$30,158,455	$26,471,893	$23,451,810	$21,169,325	$20,320,808	$20,047,678	$21,016,090	$22,158,230	$23,352,176	$22,931,312	$21,002,701	$17,405,684	$2,748,378

Notes:
(a) Form 42-5E-2, Line 7
(b) Form 42-7E-2, Line 6
(c) Form 3E, Line 10
(d) Form 1A, Line 7
(e) As approved in Order No. PSC-2020-0433-FOF-EI issued November 13, 2020.
(f) From FPL's 2020 Final True-up filed on April 1, 2021.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Calculation of the Actual/Estimated True-Up Amount for the Period

Form 42-3E

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
1. Beginning True-Up amount for Interest Provision (a)	$33,509,034	$30,158,455	$26,471,893	$23,451,810	$21,169,325	$20,320,808	$20,047,678	$21,016,090	$22,158,230	$23,352,176	$22,931,312	$21,002,701	
2. Ending True-Up amount for Interest Provision (b)	$30,156,200	$26,469,888	$23,449,730	$21,167,652	$20,319,857	$20,047,005	$21,015,406	$22,157,510	$23,351,417	$22,930,541	$21,001,968	$17,405,044	
3. Total of Beginning & Ending True-Up (Lines 1 + 2)	$63,665,234	$56,628,343	$49,921,624	$44,619,462	$41,489,182	$40,367,813	$41,063,084	$43,173,600	$45,509,647	$46,282,716	$43,933,280	$38,407,745	
4. Average True-Up Amount (Line 3 x 1/2)	$31,832,617	$28,314,171	$24,960,812	$22,309,731	$20,744,591	$20,183,907	$20,531,542	$21,586,800	$22,754,823	$23,141,358	$21,966,640	$19,203,872	
5. Interest Rate (First Day of Reporting Month)	0.09000%	0.08000%	0.09000%	0.11000%	0.07000%	0.04000%	0.04000%	0.04000%	0.04000%	0.04000%	0.04000%	0.04000%	
6. Interest Rate (First Day of Subsequent Month)	0.08000%	0.09000%	0.11000%	0.07000%	0.04000%	0.04000%	0.04000%	0.04000%	0.04000%	0.04000%	0.04000%	0.04000%	
7. Total of Beginning & Ending Interest Rates (Lines 5 + 6)	0.17000%	0.17000%	0.20000%	0.18000%	0.11000%	0.08000%	0.08000%	0.08000%	0.08000%	0.08000%	0.08000%	0.08000%	
8. Average Interest Rate (Line 7 x 1/2)	0.08500%	0.08500%	0.10000%	0.09000%	0.05500%	0.04000%	0.04000%	0.04000%	0.04000%	0.04000%	0.04000%	0.04000%	
9. Monthly Average Interest Rate (Line 8 x 1/12)	0.00708%	0.00708%	0.00833%	0.00750%	0.00458%	0.00333%	0.00333%	0.00333%	0.00333%	0.00333%	0.00333%	0.00333%	
10. Interest Provision for the Month (Lines 4 x 9)	$2,255	$2,006	$2,080	$1,673	$951	$673	$684	$720	$758	$771	$732	$640	$13,943

Notes:

(a) Form 2E, Lines 7 + 7a + 10

(b) Line 1 + Form 2E, Lines 5 + 8

(c) Actual interest rates are developed using the AA financial 30-day rates as published by the Federal Reserve. Estimated interest rates are based on the actual rates for June 2021.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Calculation of the Actual/Estimated True-Up Amount for the Period
Variance Report of O&M Activities

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)
O&M Projects	Actual/Estimated (a)	Projection (b)	Variance Amount (c)	Variance Percent (d)
1 - Air Operating Permit Fees	$230,164	$184,714	$45,450	24.61%
3a - Continuous Emission Monitoring Systems	$366,961	$364,603	$2,358	0.65%
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	$250,061	$392,202	($142,141)	(36.24%)
8a - Oil Spill Clean-up/Response Equipment	$267,940	$267,940	$0	0%
14 - NPDES Permit Fees	$69,200	$69,200	$0	0%
19a - Substation Pollutant Discharge Prevention & Removal-Distribution	$3,371,911	$2,927,122	$444,789	15.20%
19b - Substation Pollutant Discharge Prevention & Removal-Transmission	$1,347,095	$1,266,116	$80,979	6.40%
21 - St. Lucie Turtle Nets	$329,195	$368,400	($39,205)	(10.64%)
22 - Pipeline Integrity Management	($2)	$77,500	($77,502)	(100.00%)
23 - SPCC - Spill Prevention, Control & Countermeasures	$748,442	$826,568	($78,126)	(9.45%)
24 - Manatee Reburn	$3,471	$212,332	($208,861)	(98.37%)
27 - Lowest Quality Water Source	$105,036	$102,000	$3,036	2.98%
28 - CWA 316(b) Phase II Rule	$397,890	$504,217	($106,327)	(21.09%)
29 - SCR Consumables	$464,147	$466,664	($2,517)	(0.54%)
31 - Clean Air Interstate Rule (CAIR) Compliance	$3,949,873	$3,891,050	$58,823	1.51%
33 - MATS Project	$1,618,628	$2,420,782	($802,154)	(33.14%)
37 - DeSoto Next Generation Solar Energy Center	$388,452	$546,286	($157,834)	(28.89%)
38 - Space Coast Next Generation Solar Energy Center	$259,673	$268,106	($8,433)	(3.15%)
39 - Martin Next Generation Solar Energy Center	$4,051,443	$4,065,551	($14,108)	(0.35%)
41 - Manatee Temporary Heating System	$162,330	$195,900	($33,570)	(17.14%)
42 - Turkey Point Cooling Canal Monitoring Plan	$8,166,607	$9,746,110	($1,579,504)	(16.21%)
45 - 800 MW Unit ESP	$75,000	$264,099	($189,099)	(71.60%)
47 - NPDES Permit Renewal Requirements	($4,234)	$80,996	($85,230)	(105.23%)
48 - Industrial Boiler MACT	$31,668	$65,000	($33,332)	(51.28%)
50 - Steam Electric Effluent Guidelines Revised Rules	$43,726	$0	$43,726	N/A
51 - Gopher Tortoise Relocations	$39,523	$39,523	$0	0%
123 - The Protected Species Project	$0	$100,000	($100,000)	(100.00%)
NA-Amortization of Gains on Sales of Emissions Allowances	$47	$0	$47	N/A
Total	$26,734,246	$29,712,982	($2,978,736)	(10.03%)

Notes:
(a) Twelve-month totals from Form 42-5E
(b) As approved in Order No. PSC-2020-0433-FOF-EI issued November 13, 2020.
(c) Column (2) - Column (3)
(d) Column (4) / Column (3)

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Calculation of the Actual/Estimated True-Up Amount for the Period
Variance Report of O&M Activities

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)
	Actual/Estimated (a)	Projection (b)	Variance Amount (c)	Variance Percent (d)
1. Total Recoverable Costs for O&M Activities	$26,734,246	$29,712,982	($2,978,736)	(10.03%)
2. Recoverable Costs Jurisdictionalized on:				
a. Energy	$15,305,167	$18,014,195	($2,709,028)	(15.04%)
b. Demand	$11,429,079	$11,698,787	($269,708)	(2.31%)
3. Jurisdictionalized Recoverable Costs				
a. Energy	$14,634,547	$17,224,961	($2,590,413)	(15.04%)
b. CP Demand	$7,059,988	$8,304,778	($1,244,790)	(14.99%)
c. GCP Demand	$3,931,948	$2,927,122	$1,004,826	34.33%
4. Total Jurisdictionalized Recoverable Costs for O&M Activities	$25,626,483	$28,456,861	($2,830,378)	(9.95%)

Notes:
(a) Twelve-month totals from Form 42-5E
(b) As approved in Order No. PSC-2020-0433-FOF-EI issued November 13, 2020.
(c) Column (2) - Column (3)
(d) Column (4) / Column (3)

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Calculation of the Actual/Estimated True-Up Amount for the Period
O&M Activities

Form 42-5E

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
O&M Projects	Strata	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
1 - Air Operating Permit Fees	Base	$11,135	$11,135	$11,135	$11,135	$11,135	$11,135	$11,135	$11,135	$11,135	$11,135	$11,135	$11,135	$133,620
1 - Air Operating Permit Fees	Intermediate	$6,046	$6,046	$7,208	$6,046	$7,437	$7,437	$7,437	$7,437	$7,437	$7,437	$7,437	$7,437	$84,841
1 - Air Operating Permit Fees	Peaking	$1,036	$1,036	($14,016)	$1,036	$2,373	$2,891	$2,891	$2,891	$2,891	$2,891	$2,891	$2,891	$11,703
3a - Continuous Emission Monitoring Systems	Intermediate	$78,951	$9,778	$13,092	$20,808	$13,255	$20,658	$20,658	$20,658	$20,658	$20,648	$21,193	$38,248	$298,602
3a - Continuous Emission Monitoring Systems	Peaking	$37,105	$592	$136	$2,103	$0	$2,750	$2,750	$2,750	$2,750	$2,750	$1,083	$13,590	$68,359
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Base	$0	$0	$0	$0	$0	$1,442	$1,442	$0	$0	$0	$0	$0	$2,883
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Intermediate	$0	$0	$0	$0	$2,718	$500	$0	$11,604	$0	$0	$0	$0	$14,822
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Peaking	$0	$36	$0	($323)	$4,929	$8,659	$53,658	$65,396	$50,000	$50,000	$0	$0	$232,355
8a - Oil Spill Clean-up/Response Equipment	Intermediate	$1,861	$3,037	$1,854	$6,600	$418	$2,882	$1,650	$1,650	$2,750	$3,300	$2,200	$1,272	$29,474
8a - Oil Spill Clean-up/Response Equipment	Peaking	$15,058	$24,575	$14,998	$53,400	$3,383	$23,317	$13,350	$13,350	$22,250	$26,700	$17,800	$10,286	$238,466
14 - NPDES Permit Fees	Base	$11,500	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$11,500
14 - NPDES Permit Fees	Intermediate	$28,260	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$28,260
14 - NPDES Permit Fees	Peaking	$29,440	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$29,440
19a - Substation Pollutant Discharge Prevention & Removal-Distribution	Distribution	$181,853	$257,221	$368,726	$445,657	$407,841	$220,802	$225,802	$225,802	$225,802	$280,802	$275,802	$255,802	$3,371,911
19b - Substation Pollutant Discharge Prevention & Removal-Transmission	Transmission	$147,042	$70,716	$119,516	$76,276	$218,444	$85,752	$80,752	$75,752	$75,752	$125,752	$135,752	$135,587	$1,347,095
21 - St. Lucie Turtle Nets	Base	$19,635	$19,740	$19,110	$26,509	$0	$60,000	$30,700	$30,700	$30,700	$30,700	$30,700	$30,700	$329,195
22 - Pipeline Integrity Management	Intermediate	$0	$0	$0	($1)	$0	$0	$0	$0	$0	$0	$0	$0	($1)
22 - Pipeline Integrity Management	Peaking	$0	$0	$0	($1)	$0	$0	$0	$0	$0	$0	$0	$0	($1)
23 - SPCC - Spill Prevention, Control & Countermeasures	Distribution	$28,328	$40,671	$37,144	$46,591	$39,399	$50,095	$55,245	$56,364	$52,177	$49,790	$51,485	$52,750	$560,037
23 - SPCC - Spill Prevention, Control & Countermeasures	Intermediate	$434	$0	$6,125	$279	$1,253	$729	$829	$1,329	$1,329	$1,329	$1,829	$958	$16,422
23 - SPCC - Spill Prevention, Control & Countermeasures	Peaking	$0	$0	$2,401	$0	$2,211	$571	$671	$671	$671	$877	$371	$542	$8,986
23 - SPCC - Spill Prevention, Control & Countermeasures	Transmission	$5,511	$9,955	$11,154	$11,546	$9,638	$16,463	$16,464	$16,471	$16,469	$16,336	$16,442	$16,547	$162,996
24 - Manatee Reburn	Peaking	$0	$404	$109	($2,041)	$0	$0	$0	$0	$0	$0	$5,000	$0	$3,471
27 - Lowest Quality Water Source	Intermediate	$8,770	$10,195	$8,947	$8,303	$8,129	$9,016	$8,500	$8,500	$8,500	$8,500	$8,500	$9,176	$105,036
28 - CWA 316(b) Phase II Rule	Base	$68,482	$46,617	$70,139	$3,679	$7,333	$1,807	$4,367	$1,812	$8,356	$6,913	$1,792	$4,424	$225,721
28 - CWA 316(b) Phase II Rule	Intermediate	$22,053	$5,176	$27,958	$15,208	$7,244	$19,620	$3,401	$11,906	$5,405	$11,807	$3,384	$3,461	$136,622
28 - CWA 316(b) Phase II Rule	Peaking	$218	$235	$212	$275	$192	$4,930	$4,932	$4,945	$4,942	$4,690	$4,890	$5,087	$35,547
29 - SCR Consumables	Intermediate	$18,864	$25,372	$42,595	$20,438	$42,429	$65,416	$30,416	$30,416	$30,416	$71,072	$46,748	$39,964	$464,147
31 - Clean Air Interstate Rule (CAIR) Compliance	Base	$645,847	$279,059	$251,832	$247,670	$507,919	$301,798	$337,990	$302,995	$268,600	$218,420	$218,419	$237,323	$3,817,873
31 - Clean Air Interstate Rule (CAIR) Compliance	Peaking	$8,876	$9,345	$10,280	$10,141	$10,813	$11,000	$11,000	$11,000	$11,000	$11,000	$11,720	$15,825	$132,000
33 - MATS Project	Base	$111,365	$168,111	$132,106	$134,447	$90,852	$161,699	$171,751	$162,134	$119,144	$119,138	$119,136	$128,744	$1,618,628
37 - DeSoto Next Generation Solar Energy Center	Solar	$33,059	$29,169	$47,777	$31,099	$34,912	$29,444	$33,044	$29,467	$28,197	$33,297	$30,018	$28,970	$388,452
38 - Space Coast Next Generation Solar Energy Center	Solar	$14,373	$10,938	$13,946	$10,248	$23,302	$30,723	$15,113	$23,620	$16,416	$16,526	$25,551	$58,917	$259,673
39 - Martin Next Generation Solar Energy Center	Intermediate	$218,801	$250,170	$498,654	$383,898	$345,339	$360,709	$345,336	$277,643	$277,561	$358,673	$365,200	$369,459	$4,051,443
41 - Manatee Temporary Heating System	Intermediate	$23,178	$7,316	$22,343	$9,136	$3,766	$5,000	$5,000	$16,590	$5,000	$40,000	$15,000	$10,000	$162,330
42 - Turkey Point Cooling Canal Monitoring Plan	Base	$398,801	$819,118	$409,062	$495,711	$573,875	$718,113	$606,477	$943,165	$583,493	$543,715	$634,230	$1,440,846	$8,166,607
45 - 800 MW Unit ESP	Peaking	$0	$1,114	$9,667	$11,708	$670	$0	$5,000	$5,000	$5,000	$17,511	$19,330	$0	$75,000
47 - NPDES Permit Renewal Requirements	Base	$0	$38,283	($97,788)	$17,201	($35,600)	$35,000	$0	$0	$0	$2,585	$0	$0	($40,319)
47 - NPDES Permit Renewal Requirements	Intermediate	($168)	$6,741	$2,349	$2,250	$0	$5,200	$6,000	$0	$0	$0	$7,713	$0	$30,085
47 - NPDES Permit Renewal Requirements	Peaking	$0	$0	$0	$0	$0	$0	$0	$6,000	$0	$0	$0	$0	$6,000
48 - Industrial Boiler MACT	Base	$27	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$27
48 - Industrial Boiler MACT	Intermediate	$0	$0	$0	$0	$0	$0	$11,000	$8,500	$0	$12,000	$0	$0	$31,500
48 - Industrial Boiler MACT	Peaking	$141	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$141
50 - Steam Electric Effluent Guidelines Revised Rules	Base	$0	$0	$0	$3,145	$41,127	$0	$0	$0	$0	$0	$0	$0	$44,272
50 - Steam Electric Effluent Guidelines Revised Rules	Peaking	$0	$0	$0	$0	($546)	$0	$0	$0	$0	$0	$0	$0	($546)
51 - Gopher Tortoise Relocations	Intermediate	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000	$0	$2,000
51 - Gopher Tortoise Relocations	Peaking	$0	$0	$0	$0	$0	$0	$0	$13,262	$13,262	$0	$0	$11,000	$37,523
NA-Amortization of Gains on Sales of Emissions Allowances	Base	$0	$0	($3)	$0	$0	$22	$0	$0	$22	$0	$0	$22	$65
NA-Amortization of Gains on Sales of Emissions Allowances	Intermediate	$0	$0	($12)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($12)
NA-Amortization of Gains on Sales of Emissions Allowances	Peaking	$0	$0	($6)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($6)
	Total	$2,175,882	$2,161,903	$2,048,751	$2,110,174	$2,386,188	$2,275,580	$2,124,762	$2,400,915	$1,908,085	$2,106,294	$2,094,750	$2,940,963	$26,734,246

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Calculation of the Actual/Estimated True-Up Amount for the Period
O&M Activities

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
		Monthly Data	Jurisdictionalization		Method of Classification		
O&M Projects	Strata	Twelve Month Total	Jurisdictional Factor	Juris Twelve Month Amount	Energy	CP Demand	GCP Demand
1 - Air Operating Permit Fees	Base	$133,620	95.678800%	$127,846	$127,846	$0	$0
1 - Air Operating Permit Fees	Intermediate	$84,841	94.997900%	$80,598	$80,598	$0	$0
1 - Air Operating Permit Fees	Peaking	$11,703	95.267500%	$11,149	$11,149	$0	$0
3a - Continuous Emission Monitoring Systems	Intermediate	$298,602	94.997900%	$283,666	$283,666	$0	$0
3a - Continuous Emission Monitoring Systems	Peaking	$68,359	95.267500%	$65,124	$65,124	$0	$0
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Base	$2,883	95.689100%	$2,759	$0	$2,759	$0
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Intermediate	$14,822	95.008100%	$14,082	$0	$14,082	$0
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Peaking	$232,355	95.277800%	$221,383	$0	$221,383	$0
8a - Oil Spill Clean-up/Response Equipment	Intermediate	$29,474	94.997900%	$27,999	$27,999	$0	$0
8a - Oil Spill Clean-up/Response Equipment	Peaking	$238,466	95.267500%	$227,181	$227,181	$0	$0
14 - NPDES Permit Fees	Base	$11,500	95.689100%	$11,004	$0	$11,004	$0
14 - NPDES Permit Fees	Intermediate	$28,260	95.008100%	$26,849	$0	$26,849	$0
14 - NPDES Permit Fees	Peaking	$29,440	95.277800%	$28,050	$0	$28,050	$0
19a - Substation Pollutant Discharge Prevention & Removal-Distribution	Distribution	$3,371,911	100.000000%	$3,371,911	$0	$0	$3,371,911
19b - Substation Pollutant Discharge Prevention & Removal-Transmission	Transmission	$1,347,095	90.230000%	$1,215,484	$0	$1,215,484	$0
21 - St. Lucie Turtle Nets	Base	$329,195	95.689100%	$315,004	$0	$315,004	$0
22 - Pipeline Integrity Management	Intermediate	($1)	95.008100%	($1)	$0	($1)	$0
22 - Pipeline Integrity Management	Peaking	($1)	95.277800%	($1)	$0	($1)	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Distribution	$560,037	100.000000%	$560,037	$0	$0	$560,037
23 - SPCC - Spill Prevention, Control & Countermeasures	Intermediate	$16,422	95.008100%	$15,602	$0	$15,602	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Peaking	$8,986	95.277800%	$8,562	$0	$8,562	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Transmission	$162,996	90.230000%	$147,071	$0	$147,071	$0
24 - Manatee Reburn	Peaking	$3,471	95.267500%	$3,307	$3,307	$0	$0
27 - Lowest Quality Water Source	Intermediate	$105,036	95.008100%	$99,793	$0	$99,793	$0
28 - CWA 316(b) Phase II Rule	Base	$225,721	95.689100%	$215,990	$0	$215,990	$0
28 - CWA 316(b) Phase II Rule	Intermediate	$136,622	95.008100%	$129,802	$0	$129,802	$0
28 - CWA 316(b) Phase II Rule	Peaking	$35,547	95.277800%	$33,869	$0	$33,869	$0
29 - SCR Consumables	Intermediate	$464,147	94.997900%	$440,930	$440,930	$0	$0
31 - Clean Air Interstate Rule (CAIR) Compliance	Base	$3,817,873	95.678800%	$3,652,895	$3,652,895	$0	$0
31 - Clean Air Interstate Rule (CAIR) Compliance	Peaking	$132,000	95.267500%	$125,754	$125,754	$0	$0
33 - MATS Project	Base	$1,618,628	95.678800%	$1,548,683	$1,548,683	$0	$0
37 - DeSoto Next Generation Solar Energy Center	Solar	$388,452	95.689100%	$371,706	$0	$371,706	$0
38 - Space Coast Next Generation Solar Energy Center	Solar	$259,673	95.689100%	$248,478	$0	$248,478	$0
39 - Martin Next Generation Solar Energy Center	Intermediate	$4,051,443	95.008100%	$3,849,199	$0	$3,849,199	$0
41 - Manatee Temporary Heating System	Intermediate	$162,330	94.997900%	$154,210	$154,210	$0	$0
42 - Turkey Point Cooling Canal Monitoring Plan	Base	$8,166,607	95.678800%	$7,813,711	$7,813,711	$0	$0
45 - 800 MW Unit ESP	Peaking	$75,000	95.267500%	$71,451	$71,451	$0	$0
47 - NPDES Permit Renewal Requirements	Base	($40,319)	95.689100%	($38,581)	$0	($38,581)	$0
47 - NPDES Permit Renewal Requirements	Intermediate	$30,085	95.008100%	$28,583	$0	$28,583	$0
47 - NPDES Permit Renewal Requirements	Peaking	$6,000	95.277800%	$5,717	$0	$5,717	$0
48 - Industrial Boiler MACT	Base	$27	95.689100%	$26	$0	$26	$0
48 - Industrial Boiler MACT	Intermediate	$31,500	95.008100%	$29,928	$0	$29,928	$0
48 - Industrial Boiler MACT	Peaking	$141	95.277800%	$135	$0	$135	$0
50 - Steam Electric Effluent Guidelines Revised Rules	Base	$44,272	95.689100%	$42,363	$0	$42,363	$0
50 - Steam Electric Effluent Guidelines Revised Rules	Peaking	($546)	95.277800%	($520)	$0	($520)	$0
51 - Gopher Tortoise Relocations	Intermediate	$2,000	95.008100%	$1,900	$0	$1,900	$0
51 - Gopher Tortoise Relocations	Peaking	$37,523	95.277800%	$35,751	$0	$35,751	$0
NA-Amortization of Gains on Sales of Emissions Allowances	Base	$65	95.678800%	$62	$62	$0	$0
NA-Amortization of Gains on Sales of Emissions Allowances	Intermediate	($12)	94.997900%	($11)	($11)	$0	$0
NA-Amortization of Gains on Sales of Emissions Allowances	Peaking	($6)	95.267500%	($6)	($6)	$0	$0
	Total	$26,734,246		$25,626,483	$14,634,547	$7,059,988	$3,931,948

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Calculation of the Actual/Estimated True-Up Amount for the Period
O&M Activities

Form 42-5E

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
1. Total of O&M Activities	$2,175,882	$2,161,903	$2,048,751	$2,110,174	$2,386,188	$2,275,580	$2,124,762	$2,400,915	$1,908,085	$2,106,294	$2,094,750	$2,940,963	$26,734,246
2. Recoverable Costs Jurisdictionalized on Energy													
Production - Base	$1,167,148	$1,277,424	$804,132	$888,963	$1,183,780	$1,192,768	$1,127,353	$1,419,429	$982,395	$892,408	$982,920	$1,818,071	$13,736,792
Production - Intermediate	$128,900	$51,550	$87,079	$63,027	$67,306	$101,393	$65,161	$76,751	$66,261	$142,457	$92,577	$96,921	$1,039,381
Production - Peaking	$62,075	$37,066	$21,167	$76,346	$17,239	$39,959	$34,991	$34,991	$43,891	$60,852	$57,824	$42,592	$528,994
Production - Solar													
3. Recoverable Costs Jurisdictionalized on CP Demand													
Production - Base	$99,644	$104,641	($8,539)	$50,534	$12,860	$98,248	$36,509	$32,512	$39,056	$40,198	$32,492	$35,124	$573,279
Production - Intermediate	$278,149	$272,282	$544,033	$409,937	$364,682	$395,774	$375,066	$319,482	$292,795	$392,309	$388,627	$383,054	$4,416,190
Production - Peaking	$29,800	$271	$2,613	($50)	$6,786	$14,161	$59,261	$90,274	$68,874	$55,567	$5,261	$16,629	$349,446
Production - Solar	$47,432	$40,107	$61,723	$41,346	$58,213	$60,167	$48,158	$53,087	$44,613	$49,823	$55,568	$87,887	$648,125
Transmission	$152,553	$80,670	$130,670	$87,822	$228,081	$102,216	$97,216	$92,224	$92,222	$142,088	$152,194	$152,134	$1,510,091
Distribution	$210,181	$297,892	$405,870	$492,247	$447,240	$270,897	$281,047	$282,166	$277,979	$330,592	$327,287	$308,552	$3,931,948
4. Retail Energy Jurisdictional Factors													
Production - Base	95.678800%	95.678800%	95.678800%	95.678800%	95.678800%	95.678800%	95.678800%	95.678800%	95.678800%	95.678800%	95.678800%	95.678800%	
Production - Intermediate	94.997900%	94.997900%	94.997900%	94.997900%	94.997900%	94.997900%	94.997900%	94.997900%	94.997900%	94.997900%	94.997900%	94.997900%	
Production - Peaking	95.267500%	95.267500%	95.267500%	95.267500%	95.267500%	95.267500%	95.267500%	95.267500%	95.267500%	95.267500%	95.267500%	95.267500%	
Production - Solar	95.678800%	95.678800%	95.678800%	95.678800%	95.678800%	95.678800%	95.678800%	95.678800%	95.678800%	95.678800%	95.678800%	95.678800%	
5. Retail Demand Jurisdictional Factors													
Production - Base	95.689100%	95.689100%	95.689100%	95.689100%	95.689100%	95.689100%	95.689100%	95.689100%	95.689100%	95.689100%	95.689100%	95.689100%	
Production - Intermediate	95.008100%	95.008100%	95.008100%	95.008100%	95.008100%	95.008100%	95.008100%	95.008100%	95.008100%	95.008100%	95.008100%	95.008100%	
Production - Peaking	95.277800%	95.277800%	95.277800%	95.277800%	95.277800%	95.277800%	95.277800%	95.277800%	95.277800%	95.277800%	95.277800%	95.277800%	
Production - Solar	95.689100%	95.689100%	95.689100%	95.689100%	95.689100%	95.689100%	95.689100%	95.689100%	95.689100%	95.689100%	95.689100%	95.689100%	
Transmission	90.230000%	90.230000%	90.230000%	90.230000%	90.230000%	90.230000%	90.230000%	90.230000%	90.230000%	90.230000%	90.230000%	90.230000%	
Distribution	100.000000%	100.000000%	100.000000%	100.000000%	100.000000%	100.000000%	100.000000%	100.000000%	100.000000%	100.000000%	100.000000%	100.000000%	
6. Jurisdictional Recoverable Costs													
Production - Base	$1,212,062	$1,322,354	$761,214	$898,905	$1,144,932	$1,235,238	$1,113,573	$1,389,203	$977,316	$892,311	$971,537	$1,773,118	$13,691,763
Production - Intermediate	$386,716	$307,661	$599,599	$449,348	$410,417	$472,338	$418,244	$376,446	$341,125	$508,056	$457,173	$456,005	$5,183,128
Production - Peaking	$87,530	$35,570	$22,655	$72,686	$22,889	$51,559	$89,798	$119,346	$107,436	$110,915	$60,100	$56,420	$836,904
Production - Solar	$45,387	$38,378	$59,062	$39,564	$55,704	$57,573	$46,082	$50,799	$42,690	$47,675	$53,173	$84,098	$620,185
Transmission	$137,649	$72,789	$117,904	$79,242	$205,798	$92,229	$87,718	$83,213	$83,212	$128,206	$137,325	$137,271	$1,362,555
Distribution	$210,181	$297,892	$405,870	$492,247	$447,240	$270,897	$281,047	$282,166	$277,979	$330,592	$327,287	$308,552	$3,931,948
7. Total Jurisdictional Recoverable Costs for O&M Activities	$2,079,525	$2,074,644	$1,966,305	$2,031,992	$2,286,979	$2,179,835	$2,036,462	$2,301,172	$1,829,757	$2,017,755	$2,006,595	$2,815,463	$25,626,483

Form 42-6E

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Calculation of the Actual/Estimated True-Up Amount for the Period
Variance Report of Capital Projects - Recoverable Costs

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)
Capital Projects	Actual/Estimated (a)	Projection (b)	Variance Amount (c)	Variance Percent (d)
2 - Low NOX Burner Technology	$54,128	$54,180	($53)	(0.10%)
3 - Continuous Emission Monitoring Systems	$451,822	$445,012	$6,810	1.53%
5 - Maintenance of Stationary Above Ground Fuel Tanks	$1,604,019	$1,635,231	($31,211)	(1.91%)
7 - Relocate Turbine Lube Oil Underground Piping to Above Ground	($1,451)	$1,408	($2,859)	(203.07%)
8 - Oil Spill Cleanup/Response Equipment	$189,861	$208,086	($18,224)	(8.76%)
10 - Relocate Storm Water Runoff	$6,015	$6,026	($11)	(0.18%)
12 - Scherer Discharge Pipeline	$32,591	$32,646	($55)	(0.17%)
20 - Wastewater Discharge Elimination & Reuse	$42,559	$42,694	($135)	(0.32%)
21 - St. Lucie Turtle Nets	$724,354	$726,163	($1,809)	(0.25%)
22 - Pipeline Integrity Management	$257,955	$258,532	($578)	(0.22%)
23 - SPCC - Spill Prevention, Control & Countermeasures	$2,185,488	$2,255,265	($69,777)	(3.09%)
24 - Manatee Reburn	$2,861,685	$2,865,912	($4,227)	(0.15%)
26 - UST Remove/Replacement	$6,530	$6,545	($15)	(0.23%)
28 - CWA 316(b) Phase II Rule	$76,351	$76,528	($177)	(0.23%)
31 - Clean Air Interstate Rule (CAIR) Compliance	$44,414,116	$44,511,165	($97,049)	(0.22%)
33 - MATS Project	$9,233,085	$9,252,605	($19,519)	(0.21%)
34 - St Lucie Cooling Water System Inspection & Maintenance	$356,179	$357,304	($1,125)	(0.31%)
35 - Martin Plant Drinking Water System Compliance	$14,167	$19,807	($5,640)	(28.47%)
36 - Low-Level Radioactive Waste Storage	$1,618,894	$1,622,516	($3,623)	(0.22%)
37 - DeSoto Next Generation Solar Energy Center	$11,422,133	$11,450,670	($28,537)	(0.25%)
38 - Space Coast Next Generation Solar Energy Center	$5,325,746	$5,342,024	($16,278)	(0.30%)
39 - Martin Next Generation Solar Energy Center	$32,972,967	$33,133,292	($160,326)	(0.48%)
41 - Manatee Temporary Heating System	$3,154,746	$3,171,174	($16,428)	(0.52%)
42 - Turkey Point Cooling Canal Monitoring Plan	$7,039,623	$6,807,724	$231,899	3.41%
44 - Martin Plant Barley Barber Swamp Iron Mitigation	$14,310	$14,342	($32)	(0.23%)
45 - 800 MW Unit ESP	$18,459,289	$18,500,095	($40,806)	(0.22%)
47 - NPDES Permit Renewal Requirements	$370,228	$301,421	$68,806	22.83%
50 - Steam Electric Effluent Guidelines Revised Rules	$109,680	$385,191	($275,511)	(71.53%)
54 - Coal Combustion Residuals	$11,556,346	$11,297,162	$259,184	2.29%
123 - The Protected Species Project	$18,217	$7,364	$10,854	147.39%
124 - FPL Miami-Dade Clean Water Recovery Center	$39,327	$0	$39,327	N/A
NA-Amortization of Gains on Sales of Emissions Allowances	($12)	($15)	$3	(20.22%)
Total	$154,610,949	$154,788,069	($177,121)	(0.11%)

[a] The 12-Month Totals on Form 42-7E

[b] As approved in Order No. PSC-2020-0433-FOF-EI issued November 13, 2020.

[c] Column (2) - Column (3)

[d] Column (4) / Column (3)

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Calculation of the Actual/Estimated True-Up Amount for the Period
Variance Report of Capital Projects - Recoverable Costs

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)
	Actual/Estimated (a)	Projection (b)	Variance Amount (c)	Variance Percent (d)
1. Total Recoverable Costs for Capital Projects	$154,610,949	$154,788,069	($177,121)	(0.11%)
2. Recoverable Costs Jurisdictionalized on:				
a. Energy	($12)	($15)	$3	(20.22%)
b. Demand	$154,610,960	$154,788,084	($177,124)	(0.11%)
3. Jurisdictionalized Recoverable Costs				
a. Energy	$12,905,121	$12,942,264	($37,143)	(0.29%)
b. Demand	$134,654,878	$134,775,540	($120,662)	(0.09%)
4. Total Jurisdictionalized Recoverable Costs for Capital Projects	$147,559,999	$147,717,804	($157,805)	(0.11%)

Notes:
(a) Twelve-month totals from Form 42-7E
(b) As approved in Order No. PSC-2020-0433-FOF-EI issued November 13, 2020.
(c) Column (2) - Column (3)
(d) Column (4) / Column (3)

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Calculation of the Actual/Estimated True-Up Amount for the Period
Capital Projects - Recoverable Costs

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Capital Projects	Strata	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
2 - Low NOX Burner Technology	Peaking	$4,626	$4,605	$4,584	$4,563	$4,542	$4,521	$4,500	$4,479	$4,458	$4,438	$4,417	$4,396	$54,128
3 - Continuous Emission Monitoring Systems	Base	$2,254	$2,246	$2,238	$2,230	$2,222	$2,214	$2,206	$2,198	$2,190	$2,182	$2,174	$2,166	$26,519
3 - Continuous Emission Monitoring Systems	Intermediate	$22,467	$22,401	$22,333	$22,265	$22,197	$22,130	$22,062	$21,994	$21,926	$21,859	$21,791	$21,723	$265,148
3 - Continuous Emission Monitoring Systems	Peaking	$13,579	$13,535	$13,493	$13,451	$13,409	$13,367	$13,325	$13,283	$13,241	$13,199	$13,157	$13,115	$160,155
5 - Maintenance of Stationary Above Ground Fuel Tanks	Base	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$1,803
5 - Maintenance of Stationary Above Ground Fuel Tanks	General	$58,403	$58,354	$58,305	$58,257	$58,208	$58,756	$59,300	$59,244	$59,187	$59,130	$59,074	$59,907	$706,127
5 - Maintenance of Stationary Above Ground Fuel Tanks	Intermediate	$18,371	$18,360	$18,300	$18,239	$18,179	$18,119	$18,058	$17,998	$17,938	$17,877	$17,817	$17,757	$217,012
5 - Maintenance of Stationary Above Ground Fuel Tanks	Peaking	$57,919	$57,642	$57,415	$57,187	$56,960	$56,732	$56,100	$56,280	$56,052	$55,824	$55,597	$55,369	$679,077
7 - Relocate Turbine Lube Oil Underground Piping to Above Ground	Base	$122	$121	($1,694)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1,451)
8 - Oil Spill Cleanup/Response Equipment	Distribution	$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$261
8 - Oil Spill Cleanup/Response Equipment	General	$27	$27	$27	$27	$27	$27	$27	$27	$27	$27	$27	$27	$326
8 - Oil Spill Cleanup/Response Equipment	Intermediate	$11,278	$10,372	$10,361	$10,364	$10,359	$10,353	$10,329	$10,304	$10,821	$11,334	$11,302	$11,608	$128,784
8 - Oil Spill Cleanup/Response Equipment	Peaking	$5,339	$5,064	$5,054	$5,055	$5,032	$5,008	$4,989	$4,970	$4,950	$4,931	$4,912	$5,185	$60,489
10 - Relocate Storm Water Runoff	Base	$509	$508	$506	$505	$503	$502	$501	$499	$498	$496	$495	$493	$6,015
12 - Scherer Discharge Pipeline	Base	$2,763	$2,754	$2,746	$2,737	$2,729	$2,720	$2,712	$2,703	$2,695	$2,686	$2,678	$2,669	$32,591
20 - Wastewater Discharge Elimination & Reuse	Peaking	$3,547	$3,547	$3,547	$3,547	$3,547	$3,547	$3,547	$3,547	$3,547	$3,547	$3,547	$3,547	$42,559
21 - St. Lucie Turtle Nets	Base	$60,838	$60,752	$60,665	$60,579	$60,492	$60,406	$60,320	$60,233	$60,147	$60,060	$59,974	$59,888	$724,354
22 - Pipeline Integrity Management	Intermediate	$11,690	$11,691	$11,668	$11,645	$11,623	$11,600	$11,577	$11,555	$11,532	$11,509	$11,487	$11,464	$139,040
22 - Pipeline Integrity Management	Peaking	$10,040	$9,996	$9,977	$9,957	$9,937	$9,917	$9,898	$9,878	$9,858	$9,839	$9,819	$9,799	$118,915
23 - SPCC - Spill Prevention, Control & Countermeasures	Base	$27,814	$27,732	$27,650	$27,568	$27,486	$27,404	$27,322	$27,240	$27,158	$27,076	$26,994	$26,912	$328,359
23 - SPCC - Spill Prevention, Control & Countermeasures	Distribution	$22,332	$22,183	$22,021	$21,965	$21,727	$21,545	$21,557	$21,523	$21,488	$21,454	$21,420	$21,385	$260,601
23 - SPCC - Spill Prevention, Control & Countermeasures	General	$896	$895	$893	$891	$891	$890	$888	$902	$916	$915	$944	$974	$10,894
23 - SPCC - Spill Prevention, Control & Countermeasures	Intermediate	$56,313	$56,222	$56,070	$56,284	$58,540	$60,678	$61,625	$62,370	$62,273	$62,492	$62,716	$62,573	$718,155
23 - SPCC - Spill Prevention, Control & Countermeasures	Peaking	$44,307	$44,110	$43,948	$44,061	$42,563	$40,789	$40,624	$40,544	$40,547	$40,551	$40,554	$40,474	$503,073
23 - SPCC - Spill Prevention, Control & Countermeasures	Transmission	$30,609	$30,564	$30,520	$30,484	$30,447	$30,405	$30,230	$30,318	$30,274	$30,229	$30,185	$30,140	$364,406
24 - Manatee Reburn	Peaking	$243,158	$242,307	$241,455	$240,603	$239,751	$238,900	$238,048	$237,196	$236,344	$235,493	$234,641	$233,789	$2,861,685
26 - UST Remove/Replacement	General	$549	$548	$548	$547	$546	$545	$544	$543	$542	$541	$540	$539	$6,530
28 - CWA 316(b) Phase II Rule	Intermediate	$6,426	$6,414	$6,403	$6,391	$6,380	$6,368	$6,357	$6,345	$6,334	$6,322	$6,311	$6,299	$76,351
31 - Clean Air Interstate Rule (CAIR) Compliance	Base	$3,000,168	$2,995,081	$2,990,384	$2,985,750	$2,980,718	$2,975,567	$2,970,473	$2,965,380	$2,960,286	$2,955,193	$2,950,100	$2,945,054	$35,674,154
31 - Clean Air Interstate Rule (CAIR) Compliance	Distribution	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8	$101
31 - Clean Air Interstate Rule (CAIR) Compliance	Intermediate	$9,377	$9,364	$9,348	$9,332	$9,315	$9,299	$9,283	$9,267	$9,250	$9,234	$9,218	$9,202	$111,489
31 - Clean Air Interstate Rule (CAIR) Compliance	Peaking	$726,863	$725,436	$724,013	$722,589	$721,166	$719,742	$718,319	$716,896	$715,472	$714,049	$712,625	$711,202	$8,628,373
33 - MATS Project	Base	$778,757	$777,064	$775,371	$773,672	$771,973	$770,274	$768,576	$766,877	$765,178	$763,479	$761,781	$760,084	$9,233,085
34 - St Lucie Cooling Water System Inspection & Maintenance	Base	$29,682	$29,682	$29,682	$29,682	$29,682	$29,682	$29,682	$29,682	$29,682	$29,682	$29,682	$29,682	$356,179
35 - Martin Plant Drinking Water System Compliance	Intermediate	$673	$673	$673	$673	$673	$673	$673	$673	$673	$673	$673	$673	$8,075
35 - Martin Plant Drinking Water System Compliance	Peaking	$508	$508	$508	$508	$508	$508	$508	$508	$508	$508	$508	$508	$6,092
36 - Low-Level Radioactive Waste Storage	Base	$136,374	$136,107	$135,841	$135,574	$135,308	$135,041	$134,775	$134,508	$134,241	$133,975	$133,708	$133,442	$1,618,894
37 - DeSoto Next Generation Solar Energy Center	Solar	$968,633	$965,470	$962,308	$959,145	$956,051	$953,036	$950,102	$947,505	$944,755	$941,561	$938,366	$935,200	$11,422,133
38 - Space Coast Next Generation Solar Energy Center	Solar	$451,559	$450,147	$448,735	$447,323	$445,911	$444,502	$443,099	$441,698	$440,295	$438,893	$437,490	$436,092	$5,325,746
39 - Martin Next Generation Solar Energy Center	Intermediate	$2,782,095	$2,777,610	$2,773,411	$2,767,308	$2,760,198	$2,753,150	$2,745,893	$2,738,151	$2,730,391	$2,722,660	$2,714,929	$2,707,169	$32,972,967
41 - Manatee Temporary Heating System	Distribution	$1,519	$1,519	$1,519	$1,519	$1,519	$1,519	$1,519	$1,519	$1,519	$1,519	$1,519	$1,519	$18,226
41 - Manatee Temporary Heating System	Intermediate	$268,538	$267,242	$265,944	$199,544	$248,708	$262,045	$260,735	$259,425	$258,115	$256,805	$255,495	$254,185	$3,056,779
41 - Manatee Temporary Heating System	Peaking	$0	$0	$0	$65,103	$14,638	$0	$0	$0	$0	$0	$0	$0	$79,741
42 - Turkey Point Cooling Canal Monitoring Plan	Base	$571,384	$570,057	$569,695	$570,974	$575,631	$582,971	$588,821	$594,890	$601,271	$603,493	$603,323	$607,791	$7,040,300
42 - Turkey Point Cooling Canal Monitoring Plan	Intermediate	($677)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($677)
44 - Martin Plant Barley Barber Swamp Iron Mitigation	Intermediate	$687	$686	$684	$683	$682	$680	$679	$678	$676	$675	$674	$673	$8,157
44 - Martin Plant Barley Barber Swamp Iron Mitigation	Peaking	$518	$517	$516	$515	$514	$513	$512	$511	$510	$509	$508	$507	$6,153
45 - 800 MW Unit ESP	Intermediate	$706	$708	$705	$703	$700	$697	$694	$691	$689	$686	$683	$680	$8,343
45 - 800 MW Unit ESP	Peaking	$1,553,294	$1,550,412	$1,547,557	$1,544,685	$1,541,873	$1,539,079	$1,536,202	$1,533,324	$1,530,447	$1,527,569	$1,524,692	$1,521,814	$18,450,946
47 - NPDES Permit Renewal Requirements	Base	$15,866	$16,165	$16,939	$18,067	$18,580	$21,029	$24,847	$34,884	$43,543	$49,551	$55,423	$55,333	$370,228
50 - Steam Electric Effluent Guidelines Revised Rules	Base	$12,318	$13,550	$13,581	$13,696	$9,659	$5,691	$6,026	$6,361	$6,696	$7,032	$7,367	$7,702	$109,680
54 - Coal Combustion Residuals	Base	$961,965	$969,000	$968,186	$967,518	$966,660	$965,077	$963,496	$961,914	$960,333	$958,751	$957,169	$956,277	$11,556,346
123 - The Protected Species Project	Intermediate	$429	$1,147	$1,300	$1,142	$1,140	$1,138	$1,237	$1,335	$1,909	$2,482	$2,480	$2,478	$18,217
124 - FPL Miami-Dade Clean Water Recovery Center	Intermediate	$0	$0	$0	$0	$0	$0	$0	$1,201	$4,019	$7,487	$11,236	$15,385	$39,327
NA-Amortization of Gains on Sales of Emissions Allowances	Base	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($12)
	Total	$12,987,591	$12,971,275	$12,946,112	$12,925,286	$12,900,285	$12,879,536	$12,862,975	$12,854,229	$12,845,581	$12,830,655	$12,812,396	$12,795,030	$154,610,949

Notes:

(a) Total Recoverable Costs from Form 42-8E, Line 9.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Calculation of the Actual/Estimated True-Up Amount for the Period
Capital Projects - Recoverable Costs

Form 42-7E

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Capital Projects	Strata	Monthly Data	Jurisdictionalization		Method of Classification		
		Twelve Month Total	Jurisdictional Factor	Juris Twelve Month Amount	Energy	CP Demand	GCP Demand
2 - Low NOX Burner Technology	Peaking	$54,128	95.277800%	$51,572	$51,572	$0	$0
3 - Continuous Emission Monitoring Systems	Base	$26,519	95.689100%	$25,376	$25,376	$0	$0
3 - Continuous Emission Monitoring Systems	Intermediate	$265,148	95.008100%	$251,912	$251,912	$0	$0
3 - Continuous Emission Monitoring Systems	Peaking	$160,155	95.277800%	$152,592	$152,592	$0	$0
5 - Maintenance of Stationary Above Ground Fuel Tanks	Base	$1,803	95.689100%	$1,726	$133	$1,593	$0
5 - Maintenance of Stationary Above Ground Fuel Tanks	General	$706,127	96.988800%	$684,864	$52,682	$632,182	$0
5 - Maintenance of Stationary Above Ground Fuel Tanks	Intermediate	$217,012	95.008100%	$206,179	$15,860	$190,319	$0
5 - Maintenance of Stationary Above Ground Fuel Tanks	Peaking	$679,077	95.277800%	$647,010	$49,770	$597,240	$0
7 - Relocate Turbine Lube Oil Underground Piping to Above Ground	Base	($1,451)	95.689100%	($1,388)	($107)	($1,282)	$0
8 - Oil Spill Cleanup/Response Equipment	Distribution	$261	100.000000%	$261	$0	$0	$261
8 - Oil Spill Cleanup/Response Equipment	General	$326	96.988800%	$316	$24	$292	$0
8 - Oil Spill Cleanup/Response Equipment	Intermediate	$128,784	95.008100%	$122,356	$9,412	$112,944	$0
8 - Oil Spill Cleanup/Response Equipment	Peaking	$60,489	95.277800%	$57,633	$4,433	$53,200	$0
10 - Relocate Storm Water Runoff	Base	$6,015	95.689100%	$5,756	$443	$5,313	$0
12 - Scherer Discharge Pipeline	Base	$32,591	95.689100%	$31,186	$2,399	$28,787	$0
20 - Wastewater Discharge Elimination & Reuse	Peaking	$42,559	95.277800%	$40,549	$3,119	$37,430	$0
21 - St. Lucie Turtle Nets	Base	$724,354	95.689100%	$693,128	$53,318	$639,810	$0
22 - Pipeline Integrity Management	Intermediate	$139,040	95.008100%	$132,099	$10,161	$121,937	$0
22 - Pipeline Integrity Management	Peaking	$118,915	95.277800%	$113,300	$8,715	$104,584	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Base	$328,359	95.689100%	$314,204	$24,170	$290,034	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Distribution	$260,601	100.000000%	$260,601	$0	$0	$260,601
23 - SPCC - Spill Prevention, Control & Countermeasures	General	$10,894	96.988800%	$10,566	$813	$9,754	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Intermediate	$718,155	95.008100%	$682,306	$52,485	$629,821	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Peaking	$503,073	95.277800%	$479,317	$36,871	$442,446	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Transmission	$364,406	90.230000%	$328,803	$25,293	$303,511	$0
24 - Manatee Reburn	Peaking	$2,861,685	95.277800%	$2,726,551	$2,726,551	$0	$0
26 - UST Remove/Replacement	General	$6,530	96.988800%	$6,333	$487	$5,846	$0
28 - CWA 316(b) Phase II Rule	Intermediate	$76,351	95.008100%	$72,539	$5,580	$66,959	$0
31 - Clean Air Interstate Rule (CAIR) Compliance	Base	$35,674,154	95.689100%	$34,136,277	$2,625,867	$31,510,409	$0
31 - Clean Air Interstate Rule (CAIR) Compliance	Distribution	$101	100.000000%	$101	$0	$0	$101
31 - Clean Air Interstate Rule (CAIR) Compliance	Intermediate	$111,489	95.008100%	$105,924	$8,148	$97,776	$0
31 - Clean Air Interstate Rule (CAIR) Compliance	Peaking	$8,628,373	95.277800%	$8,220,924	$632,379	$7,588,545	$0
33 - MATS Project	Base	$9,233,085	95.689100%	$8,835,056	$679,620	$8,155,436	$0
34 - St Lucie Cooling Water System Inspection & Maintenance	Base	$356,179	95.689100%	$340,825	$26,217	$314,607	$0
35 - Martin Plant Drinking Water System Compliance	Intermediate	$8,075	95.008100%	$7,672	$590	$7,082	$0
35 - Martin Plant Drinking Water System Compliance	Peaking	$6,092	95.277800%	$5,804	$446	$5,358	$0
36 - Low-Level Radioactive Waste Storage	Base	$1,618,894	95.689100%	$1,549,105	$119,162	$1,429,943	$0
37 - DeSoto Next Generation Solar Energy Center	Solar	$11,422,133	95.689100%	$10,929,736	$840,749	$10,088,988	$0

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Calculation of the Actual/Estimated True-Up Amount for the Period
Capital Projects - Recoverable Costs

Form 42-7E

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Capital Projects	Strata	Monthly Data	Jurisdictionalization		Method of Classification		
		Twelve Month Total	Jurisdictional Factor	Juris Twelve Month Amount	Energy	CP Demand	GCP Demand
38 - Space Coast Next Generation Solar Energy Center	Solar	$5,325,746	95.689100%	$5,096,159	$392,012	$4,704,146	$0
39 - Martin Next Generation Solar Energy Center	Intermediate	$32,972,967	95.008100%	$31,326,989	$2,409,768	$28,917,221	$0
41 - Manatee Temporary Heating System	Distribution	$18,226	100.000000%	$18,226	$0	$0	$18,226
41 - Manatee Temporary Heating System	Intermediate	$3,056,779	95.008100%	$2,904,188	$223,399	$2,680,789	$0
41 - Manatee Temporary Heating System	Peaking	$79,741	95.277800%	$75,975	$5,844	$70,131	$0
42 - Turkey Point Cooling Canal Monitoring Plan	Base	$7,040,300	95.689100%	$6,736,800	$518,215	$6,218,584	$0
42 - Turkey Point Cooling Canal Monitoring Plan	Intermediate	($677)	95.008100%	($644)	($50)	($594)	$0
44 - Martin Plant Barley Barber Swamp Iron Mitigation	Intermediate	$8,157	95.008100%	$7,750	$0	$7,750	$0
44 - Martin Plant Barley Barber Swamp Iron Mitigation	Peaking	$6,153	95.277800%	$5,863	$0	$5,863	$0
45 - 800 MW Unit ESP	Intermediate	$8,343	95.008100%	$7,926	$0	$7,926	$0
45 - 800 MW Unit ESP	Peaking	$18,450,946	95.277800%	$17,579,656	$0	$17,579,656	$0
47 - NPDES Permit Renewal Requirements	Base	$370,228	95.689100%	$354,267	$0	$354,267	$0
50 - Steam Electric Effluent Guidelines Revised Rules	Base	$109,680	95.689100%	$104,951	$8,073	$96,878	$0
54 - Coal Combustion Residuals	Base	$11,556,346	95.689100%	$11,058,164	$850,628	$10,207,536	$0
123 - The Protected Species Project	Intermediate	$18,217	95.008100%	$17,308	$0	$17,308	$0
124 - FPL Miami-Dade Clean Water Recovery Center	Intermediate	$39,327	95.008100%	$37,364	$0	$37,364	$0
NA-Amortization of Gains on Sales of Emissions Allowances	Base	($12)	95.678800%	($11)	($11)	$0	$0
	Total	$154,610,949		$147,559,999	$12,905,121	$134,375,690	$279,188

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Calculation of the Actual/Estimated True-Up Amount for the Period
Capital Projects - Recoverable Costs

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
1. Total of Capital Projects	$12,987,591	$12,971,275	$12,946,112	$12,925,286	$12,900,285	$12,879,536	$12,862,975	$12,854,229	$12,845,581	$12,830,655	$12,812,396	$12,795,030	$154,610,949
2. Recoverable Costs Jurisdictionalized on Energy													
Production - Base	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($12)
3. Recoverable Costs Jurisdictionalized on Demand													
Production - Base	$5,600,964	$5,600,969	$5,591,940	$5,588,702	$5,581,794	$5,578,729	$5,579,904	$5,587,520	$5,594,068	$5,593,806	$5,591,017	$5,587,643	$67,077,056
Production - Intermediate	$3,188,373	$3,182,890	$3,177,201	$3,104,573	$3,148,694	$3,156,931	$3,149,202	$3,141,986	$3,136,545	$3,132,095	$3,126,810	$3,121,868	$37,767,167
Production - Peaking	$2,663,698	$2,657,678	$2,652,065	$2,711,824	$2,654,439	$2,632,623	$2,626,572	$2,621,415	$2,615,935	$2,610,456	$2,604,976	$2,599,706	$31,651,387
Production - Solar	$1,420,192	$1,415,618	$1,411,044	$1,406,468	$1,401,962	$1,397,538	$1,393,202	$1,389,203	$1,385,051	$1,380,454	$1,375,856	$1,371,292	$16,747,879
General	$59,875	$59,825	$59,773	$59,722	$59,672	$60,218	$60,760	$60,716	$60,672	$60,613	$60,584	$61,448	$723,877
Transmission	$30,609	$30,564	$30,520	$30,484	$30,447	$30,405	$30,230	$30,318	$30,274	$30,229	$30,185	$30,140	$364,406
Distribution	$23,881	$23,732	$23,570	$23,514	$23,277	$23,094	$23,106	$23,072	$23,037	$23,003	$22,968	$22,934	$279,188
4. Retail Demand Jurisdictional Factors													
Production - Base	95.689100%	95.689100%	95.689100%	95.689100%	95.689100%	95.689100%	95.689100%	95.689100%	95.689100%	95.689100%	95.689100%	95.689100%	
Production - Intermediate	95.008100%	95.008100%	95.008100%	95.008100%	95.008100%	95.008100%	95.008100%	95.008100%	95.008100%	95.008100%	95.008100%	95.008100%	
Production - Peaking	95.277800%	95.277800%	95.277800%	95.277800%	95.277800%	95.277800%	95.277800%	95.277800%	95.277800%	95.277800%	95.277800%	95.277800%	
Production - Solar	95.689100%	95.689100%	95.689100%	95.689100%	95.689100%	95.689100%	95.689100%	95.689100%	95.689100%	95.689100%	95.689100%	95.689100%	
General	96.988800%	96.988800%	96.988800%	96.988800%	96.988800%	96.988800%	96.988800%	96.988800%	96.988800%	96.988800%	96.988800%	96.988800%	
Transmission	90.230000%	90.230000%	90.230000%	90.230000%	90.230000%	90.230000%	90.230000%	90.230000%	90.230000%	90.230000%	90.230000%	90.230000%	
Distribution	100.000000%	100.000000%	100.000000%	100.000000%	100.000000%	100.000000%	100.000000%	100.000000%	100.000000%	100.000000%	100.000000%	100.000000%	
5. Jurisdictional Recoverable Costs													
Production - Base	$5,359,511	$5,359,516	$5,350,876	$5,347,778	$5,341,168	$5,338,234	$5,339,359	$5,346,646	$5,352,912	$5,352,662	$5,349,993	$5,346,764	$64,185,420
Production - Intermediate	$3,029,212	$3,024,004	$3,018,598	$2,949,596	$2,991,515	$2,999,340	$2,991,997	$2,985,141	$2,979,971	$2,975,744	$2,970,723	$2,966,028	$35,881,868
Production - Peaking	$2,537,912	$2,532,177	$2,526,830	$2,583,766	$2,529,091	$2,508,305	$2,502,540	$2,497,627	$2,492,406	$2,487,185	$2,481,964	$2,476,942	$30,156,745
Production - Solar	$1,358,969	$1,354,592	$1,350,215	$1,345,837	$1,341,525	$1,337,291	$1,333,142	$1,329,316	$1,325,343	$1,320,944	$1,316,545	$1,312,177	$16,025,895
General	$58,072	$58,023	$57,973	$57,924	$57,875	$58,404	$58,930	$58,888	$58,845	$58,788	$58,760	$59,597	$702,079
Transmission	$27,618	$27,578	$27,538	$27,505	$27,473	$27,434	$27,276	$27,356	$27,316	$27,276	$27,236	$27,196	$328,803
Distribution	$23,881	$23,732	$23,570	$23,514	$23,277	$23,094	$23,106	$23,072	$23,037	$23,003	$22,968	$22,934	$279,188
6. Total Jurisdictional Recoverable Costs for Capital Projects	$12,395,177	$12,379,622	$12,355,601	$12,335,920	$12,311,923	$12,292,104	$12,276,351	$12,268,045	$12,259,830	$12,245,601	$12,228,188	$12,211,638	$147,559,999

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
2 - Low NOX Burner Technology														
Peaking														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3. Less: Accumulated Depreciation	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	
a. Less: Capital Recovery Unamortized Balance	($225,496)	($222,364)	($219,233)	($216,101)	($212,969)	($209,837)	($206,705)	($203,573)	($200,441)	($197,309)	($194,177)	($191,045)	($187,914)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$225,496	$222,365	$219,233	$216,101	$212,969	$209,837	$206,705	$203,573	$200,441	$197,310	$194,178	$191,046	$187,914	
6. Average Net Investment		$223,931	$220,799	$217,667	$214,535	$211,403	$208,271	$205,139	$202,007	$198,876	$195,744	$192,612	$189,480	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$1,269	$1,251	$1,233	$1,215	$1,198	$1,180	$1,162	$1,144	$1,127	$1,109	$1,091	$1,074	$14,053
b. Debt Component (Line 6 x debt rate) (c)		$225	$222	$219	$216	$212	$209	$206	$203	$200	$197	$193	$190	$2,492
8. Investment Expenses														
a. Depreciation (d)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization		$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$37,583
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$4,626	$4,605	$4,584	$4,563	$4,542	$4,521	$4,500	$4,479	$4,458	$4,438	$4,417	$4,396	$54,128

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
3 - Continuous Emission Monitoring Systems														
Base														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$515,653	$515,653	$515,653	$515,653	$515,653	$515,653	$515,653	$515,653	$515,653	$515,653	$515,653	$515,653	$515,653	
3. Less: Accumulated Depreciation	$419,486	$420,685	$421,884	$423,083	$424,282	$425,481	$426,680	$427,879	$429,078	$430,276	$431,475	$432,674	$433,873	
a. Less: Capital Recovery Unamortized Balance	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$158,770	$157,571	$156,372	$155,173	$153,974	$152,775	$151,576	$150,377	$149,179	$147,980	$146,781	$145,582	$144,383	
6. Average Net Investment		$158,170	$156,971	$155,772	$154,574	$153,375	$152,176	$150,977	$149,778	$148,579	$147,380	$146,181	$144,982	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$896	$889	$883	$876	$869	$862	$855	$849	$842	$835	$828	$821	$10,305
b. Debt Component (Line 6 x debt rate) (c)		$159	$158	$156	$155	$154	$153	$152	$150	$149	$148	$147	$146	$1,827
8. Investment Expenses														
a. Depreciation (d)		$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$14,387
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$2,254	$2,246	$2,238	$2,230	$2,222	$2,214	$2,206	$2,198	$2,190	$2,182	$2,174	$2,166	$26,519

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
3 - Continuous Emission Monitoring Systems Intermediate														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$2,290,167	$2,291,141	$2,291,141	$2,291,141	$2,291,141	$2,291,141	$2,291,141	$2,291,141	$2,291,141	$2,291,141	$2,291,141	$2,291,141	$2,291,141	
3. Less: Accumulated Depreciation	$614,329	$622,437	$630,179	$637,921	$645,664	$653,406	$661,148	$668,890	$676,632	$684,374	$692,116	$699,858	$707,600	
a. Less: Capital Recovery Unamortized Balance	($174,048)	($171,630)	($169,213)	($166,796)	($164,378)	($161,961)	($159,544)	($157,126)	($154,709)	($152,292)	($149,874)	($147,457)	($145,040)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,849,885	$1,840,334	$1,830,175	$1,820,015	$1,809,856	$1,799,696	$1,789,537	$1,779,378	$1,769,218	$1,759,059	$1,748,899	$1,738,740	$1,728,580	
6. Average Net Investment		$1,845,109	$1,835,254	$1,825,095	$1,814,936	$1,804,776	$1,794,617	$1,784,457	$1,774,298	$1,764,138	$1,753,979	$1,743,820	$1,733,660	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$10,454	$10,398	$10,340	$10,283	$10,225	$10,168	$10,110	$10,052	$9,995	$9,937	$9,880	$9,822	$121,664
b. Debt Component (Line 6 x debt rate) (c)		$1,853	$1,844	$1,833	$1,823	$1,813	$1,803	$1,792	$1,782	$1,772	$1,762	$1,752	$1,741	$21,571
8. Investment Expenses														
a. Depreciation (d)		$7,742	$7,742	$7,742	$7,742	$7,742	$7,742	$7,742	$7,742	$7,742	$7,742	$7,742	$7,742	$92,905
b. Amortization		$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$29,008
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$22,467	$22,401	$22,333	$22,265	$22,197	$22,130	$22,062	$21,994	$21,926	$21,859	$21,791	$21,723	$265,148

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
3 - Continuous Emission Monitoring Systems														
Peaking														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$1,201,724	$1,200,749	$1,200,749	$1,200,749	$1,200,749	$1,200,749	$1,200,749	$1,200,749	$1,200,749	$1,200,749	$1,200,749	$1,200,749	$1,200,749	
3. Less: Accumulated Depreciation	$231,312	$235,477	$240,007	$244,538	$249,068	$253,598	$258,129	$262,659	$267,189	$271,720	$276,250	$280,781	$285,311	
a. Less: Capital Recovery Unamortized Balance	($126,397)	($124,642)	($122,886)	($121,130)	($119,375)	($117,619)	($115,864)	($114,108)	($112,353)	($110,597)	($108,842)	($107,086)	($105,331)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,096,808	$1,089,914	$1,083,628	$1,077,342	$1,071,056	$1,064,770	$1,058,484	$1,052,198	$1,045,913	$1,039,627	$1,033,341	$1,027,055	$1,020,769	
6. Average Net Investment		$1,093,361	$1,086,771	$1,080,485	$1,074,199	$1,067,913	$1,061,627	$1,055,341	$1,049,056	$1,042,770	$1,036,484	$1,030,198	$1,023,912	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$6,195	$6,157	$6,122	$6,086	$6,050	$6,015	$5,979	$5,944	$5,908	$5,872	$5,837	$5,801	$71,965
b. Debt Component (Line 6 x debt rate) (c)		$1,098	$1,092	$1,085	$1,079	$1,073	$1,066	$1,060	$1,054	$1,047	$1,041	$1,035	$1,029	$12,759
8. Investment Expenses														
a. Depreciation (d)		$4,530	$4,530	$4,530	$4,530	$4,530	$4,530	$4,530	$4,530	$4,530	$4,530	$4,530	$4,530	$54,365
b. Amortization		$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$21,066
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$13,579	$13,535	$13,493	$13,451	$13,409	$13,367	$13,325	$13,283	$13,241	$13,199	$13,157	$13,115	$160,155

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
5 - Maintenance of Stationary Above Ground Fuel Tanks Base														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3. Less: Accumulated Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
a. Less: Capital Recovery Unamortized Balance	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	
6. Average Net Investment		$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$128	$128	$128	$128	$128	$128	$128	$128	$128	$128	$128	$128	$1,532
b. Debt Component (Line 6 x debt rate) (c)		$23	$23	$23	$23	$23	$23	$23	$23	$23	$23	$23	$23	$272
8. Investment Expenses														
a. Depreciation (d)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$1,803

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
5 - Maintenance of Stationary Above Ground Fuel Tanks General														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$958,095	$0	$0	$0	$0	$0	$1,429,288	$2,387,383
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$5,837,840	$5,837,840	$5,837,840	$5,837,840	$5,837,840	$5,837,840	$6,795,935	$6,795,935	$6,795,935	$6,795,935	$6,795,935	$6,795,935	$8,225,223	
3. Less: Accumulated Depreciation	$559,703	$567,000	$574,298	$581,595	$588,892	$596,189	$604,086	$612,580	$621,075	$629,570	$638,065	$646,560	$655,948	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$2,387,383	$2,387,383	$2,387,383	$2,387,383	$2,387,383	$2,387,383	$1,429,288	$1,429,288	$1,429,288	$1,429,288	$1,429,288	$1,429,288	$0	
5. Net Investment (Lines 2 - 3 + 4)	$7,665,520	$7,658,222	$7,650,925	$7,643,628	$7,636,330	$7,629,033	$7,621,137	$7,612,642	$7,604,147	$7,595,652	$7,587,157	$7,578,662	$7,569,274	
6. Average Net Investment		$7,661,871	$7,654,574	$7,647,276	$7,639,979	$7,632,682	$7,625,085	$7,616,890	$7,608,395	$7,599,900	$7,591,405	$7,582,910	$7,573,968	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$43,409	$43,368	$43,326	$43,285	$43,244	$43,201	$43,154	$43,106	$43,058	$43,010	$42,962	$42,911	$518,035
b. Debt Component (Line 6 x debt rate) (c)		$7,696	$7,689	$7,682	$7,674	$7,667	$7,659	$7,651	$7,643	$7,634	$7,626	$7,617	$7,608	$91,846
8. Investment Expenses														
a. Depreciation (d)		$7,297	$7,297	$7,297	$7,297	$7,297	$7,896	$8,495	$8,495	$8,495	$8,495	$8,495	$9,388	$96,245
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$58,403	$58,354	$58,305	$58,257	$58,208	$58,756	$59,300	$59,244	$59,187	$59,130	$59,074	$59,907	$706,127

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
5 - Maintenance of Stationary Above Ground Fuel Tanks Intermediate														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$2,214,496	$2,263,300	$2,263,300	$2,263,300	$2,263,300	$2,263,300	$2,263,300	$2,263,300	$2,263,300	$2,263,300	$2,263,300	$2,263,300	$2,263,300	
3. Less: Accumulated Depreciation	$1,041,927	$1,082,013	$1,087,959	$1,093,905	$1,099,850	$1,105,796	$1,111,742	$1,117,688	$1,123,633	$1,129,579	$1,135,525	$1,141,471	$1,147,416	
a. Less: Capital Recovery Unamortized Balance	($222,605)	($219,504)	($216,403)	($213,302)	($210,201)	($207,100)	($203,999)	($200,899)	($197,798)	($194,697)	($191,596)	($188,495)	($185,394)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,395,175	$1,400,791	$1,391,744	$1,382,697	$1,373,651	$1,364,604	$1,355,557	$1,346,511	$1,337,464	$1,328,417	$1,319,370	$1,310,324	$1,301,277	
6. Average Net Investment		$1,397,983	$1,396,268	$1,387,221	$1,378,174	$1,369,127	$1,360,081	$1,351,034	$1,341,987	$1,332,940	$1,323,894	$1,314,847	$1,305,800	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$7,920	$7,911	$7,859	$7,808	$7,757	$7,706	$7,654	$7,603	$7,552	$7,501	$7,449	$7,398	$92,119
b. Debt Component (Line 6 x debt rate) (c)		$1,404	$1,403	$1,393	$1,384	$1,375	$1,366	$1,357	$1,348	$1,339	$1,330	$1,321	$1,312	$16,333
8. Investment Expenses														
a. Depreciation (d)		$5,946	$5,946	$5,946	$5,946	$5,946	$5,946	$5,946	$5,946	$5,946	$5,946	$5,946	$5,946	$71,349
b. Amortization		$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$37,212
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$18,371	$18,360	$18,300	$18,239	$18,179	$18,119	$18,058	$17,998	$17,938	$17,877	$17,817	$17,757	$217,012

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

Form 42-8E

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
5 - Maintenance of Stationary Above Ground Fuel Tanks														
Peaking														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$3,459,114	$3,410,311	$3,410,311	$3,410,311	$3,410,311	$3,410,311	$3,410,311	$3,410,311	$3,410,311	$3,410,311	$3,410,311	$3,410,311	$3,410,311	
3. Less: Accumulated Depreciation	$1,537,970	$1,514,746	$1,525,662	$1,536,579	$1,547,495	$1,558,411	$1,569,327	$1,579,838	$1,590,755	$1,601,671	$1,612,587	$1,623,503	$1,634,420	
a. Less: Capital Recovery Unamortized Balance	($1,671,358)	($1,648,156)	($1,624,953)	($1,601,750)	($1,578,547)	($1,555,344)	($1,532,142)	($1,508,939)	($1,485,736)	($1,462,533)	($1,439,330)	($1,416,127)	($1,392,925)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$3,592,503	$3,543,720	$3,509,601	$3,475,482	$3,441,363	$3,407,244	$3,373,125	$3,339,411	$3,305,292	$3,271,173	$3,237,054	$3,202,935	$3,168,816	
6. Average Net Investment		$3,568,111	$3,526,661	$3,492,542	$3,458,423	$3,424,303	$3,390,184	$3,356,268	$3,322,351	$3,288,232	$3,254,113	$3,219,994	$3,185,875	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$20,216	$19,981	$19,787	$19,594	$19,401	$19,207	$19,015	$18,823	$18,630	$18,437	$18,243	$18,050	$229,384
b. Debt Component (Line 6 x debt rate) (c)		$3,584	$3,543	$3,508	$3,474	$3,440	$3,405	$3,371	$3,337	$3,303	$3,269	$3,234	$3,200	$40,669
8. Investment Expenses														
a. Depreciation (d)		$10,916	$10,916	$10,916	$10,916	$10,916	$10,916	$10,511	$10,916	$10,916	$10,916	$10,916	$10,916	$130,590
b. Amortization		$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$278,434
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$57,919	$57,642	$57,415	$57,187	$56,960	$56,732	$56,100	$56,280	$56,052	$55,824	$55,597	$55,369	$679,077

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
7 - Relocate Turbine Lube Oil Underground Piping to Above Ground Base														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	
3. Less: Accumulated Depreciation	$32,454	$32,587	$32,719	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	($1,424)	($1,557)	($1,689)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
6. Average Net Investment		($1,491)	($1,623)	($844)	$0	$0	$0	$0	$0	$0	$0	$0	$0	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		($8)	($9)	($5)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($22)
b. Debt Component (Line 6 x debt rate) (c)		($1)	($2)	($1)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($4)
8. Investment Expenses														
a. Depreciation (d)		$132	$132	($1,689)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1,424)
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$122	$121	($1,694)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1,451)

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
8 - Oil Spill Cleanup/Response Equipment														
Distribution														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	
3. Less: Accumulated Depreciation	$449	$453	$458	$463	$468	$473	$478	$483	$488	$493	$498	$503	$508	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$2,547	$2,542	$2,537	$2,532	$2,527	$2,522	$2,517	$2,512	$2,507	$2,502	$2,497	$2,492	$2,487	
6. Average Net Investment		$2,544	$2,539	$2,534	$2,529	$2,524	$2,519	$2,514	$2,509	$2,504	$2,499	$2,494	$2,489	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$14	$14	$14	$14	$14	$14	$14	$14	$14	$14	$14	$14	$171
b. Debt Component (Line 6 x debt rate) (c)		$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$30
8. Investment Expenses														
a. Depreciation (d)		$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$60
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$261

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
8 - Oil Spill Cleanup/Response Equipment														
General														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	
3. Less: Accumulated Depreciation	$1,136	$1,141	$1,147	$1,152	$1,158	$1,163	$1,169	$1,174	$1,180	$1,185	$1,191	$1,196	$1,202	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$3,277	$3,272	$3,266	$3,261	$3,255	$3,250	$3,244	$3,239	$3,233	$3,227	$3,222	$3,216	$3,211	
6. Average Net Investment		$3,274	$3,269	$3,263	$3,258	$3,252	$3,247	$3,241	$3,236	$3,230	$3,225	$3,219	$3,214	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$19	$19	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18	$221
b. Debt Component (Line 6 x debt rate) (c)		$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$39
8. Investment Expenses														
a. Depreciation (d)		$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$66
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$27	$27	$27	$27	$27	$27	$27	$27	$27	$27	$27	$27	$326

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
8 - Oil Spill Cleanup/Response Equipment Intermediate														
1. Investments														
a. Expenditures/Additions (a)		$0	$206	$105	$0	$4,447	$0	$0	$0	$0	$0	$0	$30,573	$35,332
b. Clearings to Plant		($176,838)	($2,240)	$4,359	$114	$0	$0	$0	$0	$557,218	$0	$0	$27,581	$410,193
c. Retirements		($54,148)	($2,240)	$4,359	$114	$0	$0	$0	$0	$0	$0	$0	($2,993)	($54,908)
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$617,977	$441,835	$439,595	$443,953	$444,067	$444,067	$444,067	$444,067	$444,067	$1,001,286	$1,001,286	$1,001,286	$1,028,866	
3. Less: Accumulated Depreciation	$35,658	($14,171)	($12,752)	($4,721)	($908)	$2,791	$6,491	$10,190	$13,890	$18,132	$22,918	$27,704	$29,735	
a. Less: Capital Recovery Unamortized Balance	$132	$130	$128	$126	$125	$123	$121	$119	$117	$115	$114	$112	$110	
4. CWIP	$552,460	$552,460	$552,666	$552,771	$552,771	$558,534	$558,534	$558,534	$558,534	$1,316	$1,316	$1,316	$1,316	
5. Net Investment (Lines 2 - 3 + 4)	$1,134,647	$1,008,336	$1,004,884	$1,001,319	$997,622	$999,688	$995,990	$992,293	$988,595	$984,354	$979,570	$974,786	$1,000,338	
6. Average Net Investment		$1,071,492	$1,006,610	$1,003,102	$999,470	$998,655	$997,839	$994,141	$990,444	$986,475	$981,962	$977,178	$987,562	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$6,071	$5,703	$5,683	$5,663	$5,658	$5,653	$5,632	$5,611	$5,589	$5,563	$5,536	$5,595	$67,959
b. Debt Component (Line 6 x debt rate) (c)		$1,076	$1,011	$1,008	$1,004	$1,003	$1,002	$999	$995	$991	$986	$982	$992	$12,049
8. Investment Expenses														
a. Depreciation (d)		$4,133	$3,660	$3,672	$3,699	$3,699	$3,699	$3,699	$3,699	$4,243	$4,786	$4,786	$5,023	$48,799
b. Amortization		($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($22)
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$11,278	$10,372	$10,361	$10,364	$10,359	$10,353	$10,329	$10,304	$10,821	$11,334	$11,302	$11,608	$128,784

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
8 - Oil Spill Cleanup/Response Equipment														
Peaking														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$23,064	$23,064
b. Clearings to Plant		($40,848)	($1,690)	$3,288	$86	$0	$0	$0	$0	$0	$0	$0	$73,288	$34,124
c. Retirements		($40,848)	($1,690)	$3,288	$86	$0	$0	$0	$0	$0	$0	$0	($2,258)	($41,422)
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$435,132	$393,588	$391,898	$395,186	$395,272	$395,272	$395,272	$395,272	$395,272	$395,272	$395,272	$395,272	$468,560	
3. Less: Accumulated Depreciation	$153,698	$115,788	$116,969	$123,137	$126,123	$129,024	$131,924	$134,825	$137,726	$140,627	$143,528	$146,428	$147,288	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$52,481	$52,481	$52,481	$52,481	$52,481	$51,165	$51,165	$51,165	$51,165	$51,165	$51,165	$51,165	($1,316)	
5. Net Investment (Lines 2 - 3 + 4)	$333,916	$330,281	$327,411	$324,530	$321,630	$317,413	$314,512	$311,612	$308,711	$305,810	$302,909	$300,009	$319,955	
6. Average Net Investment		$332,098	$328,846	$325,971	$323,080	$319,522	$315,963	$313,062	$310,161	$307,260	$304,360	$301,459	$309,982	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$1,882	$1,863	$1,847	$1,830	$1,810	$1,790	$1,774	$1,757	$1,741	$1,724	$1,708	$1,756	$21,483
b. Debt Component (Line 6 x debt rate) (c)		$334	$330	$327	$325	$321	$317	$314	$312	$309	$306	$303	$311	$3,809
8. Investment Expenses														
a. Depreciation (d)		$3,124	$2,871	$2,880	$2,900	$2,901	$2,901	$2,901	$2,901	$2,901	$2,901	$2,901	$3,118	$35,198
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$5,339	$5,064	$5,054	$5,055	$5,032	$5,008	$4,989	$4,970	$4,950	$4,931	$4,912	$5,185	$60,489

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
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Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
10 - Relocate Storm Water Runoff														
Base														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	
3. Less: Accumulated Depreciation	$74,429	$74,649	$74,870	$75,091	$75,312	$75,533	$75,754	$75,975	$76,195	$76,416	$76,637	$76,858	$77,079	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$43,365	$43,144	$42,924	$42,703	$42,482	$42,261	$42,040	$41,819	$41,598	$41,378	$41,157	$40,936	$40,715	
6. Average Net Investment		$43,255	$43,034	$42,813	$42,592	$42,371	$42,151	$41,930	$41,709	$41,488	$41,267	$41,046	$40,825	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$245	$244	$243	$241	$240	$239	$238	$236	$235	$234	$233	$231	$2,858
b. Debt Component (Line 6 x debt rate) (c)		$43	$43	$43	$43	$43	$42	$42	$42	$42	$41	$41	$41	$507
8. Investment Expenses														
a. Depreciation (d)		$221	$221	$221	$221	$221	$221	$221	$221	$221	$221	$221	$221	$2,650
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$509	$508	$506	$505	$503	$502	$501	$499	$498	$496	$495	$493	$6,015

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

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January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
12 - Scherer Discharge Pipeline														
Base														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	
3. Less: Accumulated Depreciation	$630,300	$631,573	$632,846	$634,118	$635,391	$636,663	$637,936	$639,209	$640,481	$641,754	$643,026	$644,299	$645,572	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$224,023	$222,751	$221,478	$220,205	$218,933	$217,660	$216,388	$215,115	$213,842	$212,570	$211,297	$210,025	$208,752	
6. Average Net Investment		$223,387	$222,114	$220,842	$219,569	$218,297	$217,024	$215,751	$214,479	$213,206	$211,934	$210,661	$209,388	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$1,266	$1,258	$1,251	$1,244	$1,237	$1,230	$1,222	$1,215	$1,208	$1,201	$1,194	$1,186	$14,712
b. Debt Component (Line 6 x debt rate) (c)		$224	$223	$222	$221	$219	$218	$217	$215	$214	$213	$212	$210	$2,608
8. Investment Expenses														
a. Depreciation (d)		$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$15,271
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$2,763	$2,754	$2,746	$2,737	$2,729	$2,720	$2,712	$2,703	$2,695	$2,686	$2,678	$2,669	$32,591

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
20 - Wastewater Discharge Elimination & Reuse														
Peaking														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3. Less: Accumulated Depreciation	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	
6. Average Net Investment		$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$3,012	$3,012	$3,012	$3,012	$3,012	$3,012	$3,012	$3,012	$3,012	$3,012	$3,012	$3,012	$36,150
b. Debt Component (Line 6 x debt rate) (c)		$534	$534	$534	$534	$534	$534	$534	$534	$534	$534	$534	$534	$6,409
8. Investment Expenses														
a. Depreciation (d)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$3,547	$3,547	$3,547	$3,547	$3,547	$3,547	$3,547	$3,547	$3,547	$3,547	$3,547	$3,547	$42,559

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
21 - St. Lucie Turtle Nets														
Base														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	
3. Less: Accumulated Depreciation	($275,611)	($262,656)	($249,700)	($236,745)	($223,789)	($210,834)	($197,879)	($184,923)	($171,968)	($159,012)	($146,057)	($133,101)	($120,146)	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$7,185,170	$7,172,214	$7,159,259	$7,146,303	$7,133,348	$7,120,393	$7,107,437	$7,094,482	$7,081,526	$7,068,571	$7,055,615	$7,042,660	$7,029,705	
6. Average Net Investment		$7,178,692	$7,165,737	$7,152,781	$7,139,826	$7,126,870	$7,113,915	$7,100,959	$7,088,004	$7,075,049	$7,062,093	$7,049,138	$7,036,182	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$40,672	$40,598	$40,525	$40,451	$40,378	$40,305	$40,231	$40,158	$40,084	$40,011	$39,938	$39,864	$483,216
b. Debt Component (Line 6 x debt rate) (c)		$7,211	$7,198	$7,185	$7,172	$7,159	$7,146	$7,133	$7,120	$7,107	$7,094	$7,081	$7,068	$85,673
8. Investment Expenses														
a. Depreciation (d)		$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$155,465
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$60,838	$60,752	$60,665	$60,579	$60,492	$60,406	$60,320	$60,233	$60,147	$60,060	$59,974	$59,888	$724,354

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

Form 42-8E

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
22 - Pipeline Integrity Management														
Intermediate														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$1,544,262	$1,553,191	$1,553,191	$1,553,191	$1,553,191	$1,553,191	$1,553,191	$1,553,191	$1,553,191	$1,553,191	$1,553,191	$1,553,191	$1,553,191	
3. Less: Accumulated Depreciation	$303,596	$308,773	$312,175	$315,577	$318,978	$322,380	$325,782	$329,183	$332,585	$335,987	$339,388	$342,790	$346,192	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,240,666	$1,244,418	$1,241,016	$1,237,615	$1,234,213	$1,230,811	$1,227,410	$1,224,008	$1,220,606	$1,217,205	$1,213,803	$1,210,401	$1,207,000	
6. Average Net Investment		$1,242,542	$1,242,717	$1,239,315	$1,235,914	$1,232,512	$1,229,110	$1,225,709	$1,222,307	$1,218,905	$1,215,504	$1,212,102	$1,208,700	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$7,040	$7,041	$7,021	$7,002	$6,983	$6,964	$6,944	$6,925	$6,906	$6,887	$6,867	$6,848	$83,428
b. Debt Component (Line 6 x debt rate) (c)		$1,248	$1,248	$1,245	$1,241	$1,238	$1,235	$1,231	$1,228	$1,224	$1,221	$1,218	$1,214	$14,792
8. Investment Expenses														
a. Depreciation (d)		$3,402	$3,402	$3,402	$3,402	$3,402	$3,402	$3,402	$3,402	$3,402	$3,402	$3,402	$3,402	$40,820
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$11,690	$11,691	$11,668	$11,645	$11,623	$11,600	$11,577	$11,555	$11,532	$11,509	$11,487	$11,464	$139,040

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

Form 42-8E

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
22 - Pipeline Integrity Management														
Peaking														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$1,328,530	$1,319,600	$1,319,600	$1,319,600	$1,319,600	$1,319,600	$1,319,600	$1,319,600	$1,319,600	$1,319,600	$1,319,600	$1,319,600	$1,319,600	
3. Less: Accumulated Depreciation	$261,561	$262,742	$265,699	$268,656	$271,613	$274,570	$277,526	$280,483	$283,440	$286,397	$289,354	$292,311	$295,267	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,066,968	$1,056,858	$1,053,901	$1,050,944	$1,047,987	$1,045,030	$1,042,074	$1,039,117	$1,036,160	$1,033,203	$1,030,246	$1,027,289	$1,024,332	
6. Average Net Investment		$1,061,913	$1,055,379	$1,052,423	$1,049,466	$1,046,509	$1,043,552	$1,040,595	$1,037,638	$1,034,681	$1,031,725	$1,028,768	$1,025,811	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$6,016	$5,979	$5,963	$5,946	$5,929	$5,912	$5,896	$5,879	$5,862	$5,845	$5,829	$5,812	$70,868
b. Debt Component (Line 6 x debt rate) (c)		$1,067	$1,060	$1,057	$1,054	$1,051	$1,048	$1,045	$1,042	$1,039	$1,036	$1,033	$1,030	$12,565
8. Investment Expenses														
a. Depreciation (d)		$2,957	$2,957	$2,957	$2,957	$2,957	$2,957	$2,957	$2,957	$2,957	$2,957	$2,957	$2,957	$35,482
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$10,040	$9,996	$9,977	$9,957	$9,937	$9,917	$9,898	$9,878	$9,858	$9,839	$9,819	$9,799	$118,915

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
23 - SPCC - Spill Prevention, Control & Countermeasures														
Base														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	
3. Less: Accumulated Depreciation	$913,437	$925,738	$938,039	$950,340	$962,640	$974,941	$987,242	$999,543	$1,011,844	$1,024,145	$1,036,445	$1,048,746	$1,061,047	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$2,331,998	$2,319,697	$2,307,396	$2,295,095	$2,282,794	$2,270,493	$2,258,193	$2,245,892	$2,233,591	$2,221,290	$2,208,989	$2,196,688	$2,184,387	
6. Average Net Investment		$2,325,847	$2,313,546	$2,301,245	$2,288,945	$2,276,644	$2,264,343	$2,252,042	$2,239,741	$2,227,440	$2,215,140	$2,202,839	$2,190,538	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$13,177	$13,108	$13,038	$12,968	$12,899	$12,829	$12,759	$12,690	$12,620	$12,550	$12,480	$12,411	$153,528
b. Debt Component (Line 6 x debt rate) (c)		$2,336	$2,324	$2,312	$2,299	$2,287	$2,275	$2,262	$2,250	$2,237	$2,225	$2,213	$2,200	$27,220
8. Investment Expenses														
a. Depreciation (d)		$12,301	$12,301	$12,301	$12,301	$12,301	$12,301	$12,301	$12,301	$12,301	$12,301	$12,301	$12,301	$147,610
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$27,814	$27,732	$27,650	$27,568	$27,486	$27,404	$27,322	$27,240	$27,158	$27,076	$26,994	$26,912	$328,359

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
23 - SPCC - Spill Prevention, Control & Countermeasures														
Distribution														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	($28,236)	$15,586	$0	($47,877)	$63,692	$0	$0	$0	$0	$0	$0	$3,164
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$3,529,010	$3,529,010	$3,500,774	$3,516,360	$3,516,360	$3,468,483	$3,532,175	$3,532,175	$3,532,175	$3,532,175	$3,532,175	$3,532,175	$3,532,175	
3. Less: Accumulated Depreciation	$1,041,321	$1,046,482	$1,051,623	$1,056,754	$1,061,897	$1,067,005	$1,072,124	$1,077,290	$1,082,456	$1,087,621	$1,092,787	$1,097,953	$1,103,119	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$89,160	$89,160	$89,160	$66,376	$63,692	$63,692	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$2,576,850	$2,571,688	$2,538,311	$2,525,981	$2,518,155	$2,465,170	$2,460,051	$2,454,885	$2,449,719	$2,444,553	$2,439,388	$2,434,222	$2,429,056	
6. Average Net Investment		$2,574,269	$2,555,000	$2,532,146	$2,522,068	$2,491,662	$2,462,610	$2,457,468	$2,452,302	$2,447,136	$2,441,970	$2,436,805	$2,431,639	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$14,585	$14,476	$14,346	$14,289	$14,117	$13,952	$13,923	$13,894	$13,865	$13,835	$13,806	$13,777	$168,864
b. Debt Component (Line 6 x debt rate) (c)		$2,586	$2,566	$2,544	$2,533	$2,503	$2,474	$2,469	$2,463	$2,458	$2,453	$2,448	$2,443	$29,939
8. Investment Expenses														
a. Depreciation (d)		$5,161	$5,141	$5,131	$5,143	$5,108	$5,119	$5,166	$5,166	$5,166	$5,166	$5,166	$5,166	$61,797
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$22,332	$22,183	$22,021	$21,965	$21,727	$21,545	$21,557	$21,523	$21,488	$21,454	$21,420	$21,385	$260,601

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

Form 42-8E

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
23 - SPCC - Spill Prevention, Control & Countermeasures General														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	($210)	$0	$0	$0	$0	$4,500	$0	$0	$9,000	$0	$13,290
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,375	$3,375
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$146,691	$146,691	$146,691	$146,691	$146,691	$146,691	$146,691	$146,691	$146,691	$146,691	$146,691	$146,691	$150,066	
3. Less: Accumulated Depreciation	$39,793	$39,977	$40,160	$40,343	$40,527	$40,710	$40,893	$41,077	$41,260	$41,443	$41,627	$41,810	$41,996	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	($210)	$0	$0	$0	$0	$4,500	$4,500	$4,500	$13,500	$10,125	
5. Net Investment (Lines 2 - 3 + 4)	$106,898	$106,715	$106,531	$106,138	$106,165	$105,981	$105,798	$105,615	$109,931	$109,748	$109,565	$118,381	$118,196	
6. Average Net Investment		$106,806	$106,623	$106,335	$106,151	$106,073	$105,890	$105,706	$107,773	$109,840	$109,656	$113,973	$118,288	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$605	$604	$602	$601	$601	$600	$599	$611	$622	$621	$646	$670	$7,383
b. Debt Component (Line 6 x debt rate) (c)		$107	$107	$107	$107	$107	$106	$106	$108	$110	$110	$114	$119	$1,309
8. Investment Expenses														
a. Depreciation (d)		$183	$183	$183	$183	$183	$183	$183	$183	$183	$183	$183	$185	$2,202
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$896	$895	$893	$891	$891	$890	$888	$902	$916	$915	$944	$974	$10,894

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
23 - SPCC - Spill Prevention, Control & Countermeasures														
Intermediate														
1. Investments														
a. Expenditures/Additions (a)		$5,100	$0	$957	$109,381	($259,720)	$74,510	$257,529	$13,886	$5,049	$5,049	$5,359	$0	$217,100
b. Clearings to Plant		$0	$0	$0	$0	$458,704	$0	$0	$0	$0	$356,024	$5,359	$0	$820,087
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$5,257,521	$5,276,872	$5,276,872	$5,276,872	$5,276,872	$5,735,576	$5,735,576	$5,735,576	$5,735,576	$5,735,576	$6,091,600	$6,096,959	$6,096,959	
3. Less: Accumulated Depreciation	$907,633	$925,682	$938,254	$950,826	$963,399	$976,399	$989,828	$1,003,257	$1,016,685	$1,030,114	$1,043,890	$1,058,018	$1,072,152	
a. Less: Capital Recovery Unamortized Balance	($761,081)	($750,466)	($739,852)	($729,237)	($718,623)	($708,009)	($697,394)	($686,780)	($676,166)	($665,551)	($654,937)	($644,323)	($633,708)	
4. CWIP	($142,488)	($137,388)	($137,388)	($136,431)	($27,051)	($0)	$74,510	$332,039	$345,925	$350,974	($1)	($1)	($1)	
5. Net Investment (Lines 2 - 3 + 4)	$4,968,480	$4,964,269	$4,941,082	$4,918,852	$5,005,046	$5,467,186	$5,517,653	$5,751,139	$5,740,982	$5,721,988	$5,702,647	$5,683,263	$5,658,515	
6. Average Net Investment		$4,966,374	$4,952,675	$4,929,967	$4,961,949	$5,236,116	$5,492,419	$5,634,396	$5,746,060	$5,731,485	$5,712,317	$5,692,955	$5,670,889	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$28,138	$28,060	$27,931	$28,112	$29,666	$31,118	$31,922	$32,555	$32,472	$32,364	$32,254	$32,129	$366,721
b. Debt Component (Line 6 x debt rate) (c)		$4,989	$4,975	$4,952	$4,984	$5,260	$5,517	$5,660	$5,772	$5,757	$5,738	$5,719	$5,696	$65,019
8. Investment Expenses														
a. Depreciation (d)		$12,572	$12,572	$12,572	$12,572	$13,001	$13,429	$13,429	$13,429	$13,429	$13,776	$14,129	$14,134	$159,043
b. Amortization		$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$127,372
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$56,313	$56,222	$56,070	$56,284	$58,540	$60,678	$61,625	$62,370	$62,273	$62,492	$62,716	$62,573	$718,155

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

Form 42-8E

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
23 - SPCC - Spill Prevention, Control & Countermeasures														
Peaking														
1. Investments														
a. Expenditures/Additions (a)		$3,847	$0	$722	$82,515	($195,929)	$0	$0	$25,125	$25,125	$25,125	$25,125	$0	($8,345)
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$3,063,112	$3,043,760	$3,043,760	$3,043,760	$3,043,760	$3,043,760	$3,043,760	$3,043,760	$3,043,760	$3,043,760	$3,043,760	$3,043,760	$3,043,760	
3. Less: Accumulated Depreciation	$1,430,091	$1,436,196	$1,447,777	$1,459,357	$1,470,938	$1,482,519	$1,494,099	$1,505,680	$1,517,261	$1,528,842	$1,540,422	$1,552,003	$1,563,584	
a. Less: Capital Recovery Unamortized Balance	($941,423)	($928,391)	($915,360)	($902,328)	($889,297)	($876,265)	($863,234)	($850,202)	($837,171)	($824,139)	($811,108)	($798,076)	($785,045)	
4. CWIP	$395,615	$399,463	$399,463	$400,184	$482,700	$0	$0	$0	$25,125	$50,250	$75,375	$100,500	$100,500	
5. Net Investment (Lines 2 - 3 + 4)	$2,970,059	$2,935,418	$2,910,806	$2,886,916	$2,944,819	$2,437,507	$2,412,895	$2,388,282	$2,388,795	$2,389,308	$2,389,821	$2,390,333	$2,365,721	
6. Average Net Investment		$2,952,739	$2,923,112	$2,898,861	$2,915,867	$2,691,163	$2,425,201	$2,400,588	$2,388,539	$2,389,051	$2,389,564	$2,390,077	$2,378,027	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$16,729	$16,561	$16,424	$16,520	$15,247	$13,740	$13,601	$13,533	$13,535	$13,538	$13,541	$13,473	$176,443
b. Debt Component (Line 6 x debt rate) (c)		$2,966	$2,936	$2,912	$2,929	$2,703	$2,436	$2,411	$2,399	$2,400	$2,400	$2,401	$2,389	$31,283
8. Investment Expenses														
a. Depreciation (d)		$11,581	$11,581	$11,581	$11,581	$11,581	$11,581	$11,581	$11,581	$11,581	$11,581	$11,581	$11,581	$138,969
b. Amortization		$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$156,378
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$44,307	$44,110	$43,948	$44,061	$42,563	$40,789	$40,624	$40,544	$40,547	$40,551	$40,554	$40,474	$503,073

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
23 - SPCC - Spill Prevention, Control & Countermeasures Transmission														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$2,474	$0	$0	$0	$0	$0	$0	$2,474
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$4,118,278	$4,118,278	$4,118,278	$4,118,278	$4,118,278	$4,118,278	$4,120,752	$4,120,752	$4,120,752	$4,120,752	$4,120,752	$4,120,752	$4,120,752	
3. Less: Accumulated Depreciation	$525,383	$532,049	$538,715	$545,381	$552,047	$558,714	$565,381	$571,918	$578,588	$585,257	$591,927	$598,596	$605,266	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$2,474	$2,474	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$3,592,895	$3,586,229	$3,579,563	$3,572,897	$3,568,705	$3,562,038	$3,555,371	$3,548,834	$3,542,164	$3,535,495	$3,528,825	$3,522,156	$3,515,486	
6. Average Net Investment		$3,589,562	$3,582,896	$3,576,230	$3,570,801	$3,565,371	$3,558,705	$3,552,102	$3,545,499	$3,538,830	$3,532,160	$3,525,491	$3,518,821	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$20,337	$20,299	$20,262	$20,231	$20,200	$20,162	$20,125	$20,087	$20,050	$20,012	$19,974	$19,936	$241,675
b. Debt Component (Line 6 x debt rate) (c)		$3,606	$3,599	$3,592	$3,587	$3,581	$3,575	$3,568	$3,561	$3,555	$3,548	$3,541	$3,535	$42,848
8. Investment Expenses														
a. Depreciation (d)		$6,666	$6,666	$6,666	$6,666	$6,666	$6,668	$6,537	$6,670	$6,670	$6,670	$6,670	$6,670	$79,882
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$30,609	$30,564	$30,520	$30,484	$30,447	$30,405	$30,230	$30,318	$30,274	$30,229	$30,185	$30,140	$364,406

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
24 - Manatee Reburn														
Peaking														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	
3. Less: Accumulated Depreciation	$14,489,489	$14,617,186	$14,744,882	$14,872,578	$15,000,274	$15,127,970	$15,255,667	$15,383,363	$15,511,059	$15,638,755	$15,766,451	$15,894,148	$16,021,844	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$17,374,229	$17,246,533	$17,118,837	$16,991,141	$16,863,444	$16,735,748	$16,608,052	$16,480,356	$16,352,660	$16,224,963	$16,097,267	$15,969,571	$15,841,875	
6. Average Net Investment		$17,310,381	$17,182,685	$17,054,989	$16,927,293	$16,799,596	$16,671,900	$16,544,204	$16,416,508	$16,288,812	$16,161,115	$16,033,419	$15,905,723	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$98,074	$97,350	$96,627	$95,903	$95,180	$94,456	$93,733	$93,010	$92,286	$91,563	$90,839	$90,116	$1,129,137
b. Debt Component (Line 6 x debt rate) (c)		$17,388	$17,260	$17,132	$17,003	$16,875	$16,747	$16,619	$16,490	$16,362	$16,234	$16,106	$15,977	$200,193
8. Investment Expenses														
a. Depreciation (d)		$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$1,532,354
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$243,158	$242,307	$241,455	$240,603	$239,751	$238,900	$238,048	$237,196	$236,344	$235,493	$234,641	$233,789	$2,861,685

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
26 - UST Remove/Replacement														
General														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	
3. Less: Accumulated Depreciation	$54,635	$54,779	$54,923	$55,068	$55,212	$55,356	$55,501	$55,645	$55,789	$55,933	$56,078	$56,222	$56,366	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$60,812	$60,668	$60,523	$60,379	$60,235	$60,090	$59,946	$59,802	$59,658	$59,513	$59,369	$59,225	$59,080	
6. Average Net Investment		$60,740	$60,596	$60,451	$60,307	$60,163	$60,018	$59,874	$59,730	$59,585	$59,441	$59,297	$59,152	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$344	$343	$342	$342	$341	$340	$339	$338	$338	$337	$336	$335	$4,076
b. Debt Component (Line 6 x debt rate) (c)		$61	$61	$61	$61	$60	$60	$60	$60	$60	$60	$60	$59	$723
8. Investment Expenses														
a. Depreciation (d)		$144	$144	$144	$144	$144	$144	$144	$144	$144	$144	$144	$144	$1,732
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$549	$548	$548	$547	$546	$545	$544	$543	$542	$541	$540	$539	$6,530

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
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Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
28 - CWA 316(b) Phase II Rule														
Intermediate														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$771,310	$771,310	$771,310	$771,310	$771,310	$771,310	$771,310	$771,310	$771,310	$771,310	$771,310	$771,310	$771,310	
3. Less: Accumulated Depreciation	$66,264	$67,993	$69,722	$71,451	$73,180	$74,909	$76,638	$78,367	$80,096	$81,825	$83,554	$85,283	$87,012	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$705,047	$703,318	$701,589	$699,860	$698,131	$696,402	$694,673	$692,944	$691,215	$689,486	$687,757	$686,028	$684,299	
6. Average Net Investment		$704,182	$702,453	$700,724	$698,995	$697,266	$695,537	$693,808	$692,079	$690,350	$688,621	$686,892	$685,163	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$3,990	$3,980	$3,970	$3,960	$3,950	$3,941	$3,931	$3,921	$3,911	$3,901	$3,892	$3,882	$47,229
b. Debt Component (Line 6 x debt rate) (c)		$707	$706	$704	$702	$700	$699	$697	$695	$693	$692	$690	$688	$8,374
8. Investment Expenses														
a. Depreciation (d)		$1,729	$1,729	$1,729	$1,729	$1,729	$1,729	$1,729	$1,729	$1,729	$1,729	$1,729	$1,729	$20,748
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$6,426	$6,414	$6,403	$6,391	$6,380	$6,368	$6,357	$6,345	$6,334	$6,322	$6,311	$6,299	$76,351

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
31 - Clean Air Interstate Rule (CAIR) Compliance Base														
1. Investments														
a. Expenditures/Additions (a)		$0	$54,635	$139,304	$73,693	$20,069	$37,603	$37,603	$37,603	$37,603	$37,603	$37,603	($74,627)	$438,693
b. Clearings to Plant		$17,537	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$438,693	$456,230
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$362,183,674	$362,201,211	$362,201,211	$362,201,211	$362,201,211	$362,201,211	$362,201,211	$362,201,211	$362,201,211	$362,201,211	$362,201,211	$362,201,211	$362,639,904	
3. Less: Accumulated Depreciation	$75,556,803	$76,358,005	$77,159,224	$77,960,442	$78,761,661	$79,562,880	$80,364,099	$81,165,317	$81,966,536	$82,767,755	$83,568,974	$84,370,192	$85,171,835	
a. Less: Capital Recovery Unamortized Balance	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	
4. CWIP	$0	$0	$54,635	$193,939	$267,632	$287,701	$325,304	$362,907	$400,510	$438,113	$475,717	$513,320	$0	
5. Net Investment (Lines 2 - 3 + 4)	$330,066,401	$329,282,737	$328,536,153	$327,874,238	$327,146,712	$326,365,563	$325,601,947	$324,838,332	$324,074,716	$323,311,100	$322,547,485	$321,783,869	$320,907,599	
6. Average Net Investment		$329,674,569	$328,909,445	$328,205,195	$327,510,475	$326,756,137	$325,983,755	$325,220,139	$324,456,524	$323,692,908	$322,929,293	$322,165,677	$321,345,734	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$1,867,808	$1,863,473	$1,859,483	$1,855,547	$1,851,273	$1,846,897	$1,842,571	$1,838,244	$1,833,918	$1,829,592	$1,825,265	$1,820,620	$22,134,691
b. Debt Component (Line 6 x debt rate) (c)		$331,158	$330,390	$329,682	$328,984	$328,227	$327,451	$326,684	$325,917	$325,150	$324,382	$323,615	$322,792	$3,924,431
8. Investment Expenses														
a. Depreciation (d)		$801,202	$801,219	$801,219	$801,219	$801,219	$801,219	$801,219	$801,219	$801,219	$801,219	$801,219	$801,643	$9,615,032
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$3,000,168	$2,995,081	$2,990,384	$2,985,750	$2,980,718	$2,975,567	$2,970,473	$2,965,380	$2,960,286	$2,955,193	$2,950,100	$2,945,054	$35,674,154

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
31 - Clean Air Interstate Rule (CAIR) Compliance Distribution														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	
3. Less: Accumulated Depreciation	$460	$463	$466	$468	$471	$474	$477	$480	$482	$485	$488	$491	$494	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$853	$850	$847	$844	$841	$839	$836	$833	$830	$827	$825	$822	$819	
6. Average Net Investment		$851	$848	$846	$843	$840	$837	$834	$832	$829	$826	$823	$820	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$57
b. Debt Component (Line 6 x debt rate) (c)		$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$10
8. Investment Expenses														
a. Depreciation (d)		$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$34
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$8	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8	$101

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
31 - Clean Air Interstate Rule (CAIR) Compliance Intermediate														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$1,278,330	$1,279,846	$1,279,846	$1,279,846	$1,279,846	$1,279,846	$1,279,846	$1,279,846	$1,279,846	$1,279,846	$1,279,846	$1,279,846	$1,279,846	
3. Less: Accumulated Depreciation	$237,582	$240,439	$242,878	$245,318	$247,757	$250,197	$252,636	$255,076	$257,515	$259,954	$262,394	$264,833	$267,273	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,040,748	$1,039,407	$1,036,967	$1,034,528	$1,032,089	$1,029,649	$1,027,210	$1,024,770	$1,022,331	$1,019,891	$1,017,452	$1,015,012	$1,012,573	
6. Average Net Investment		$1,040,078	$1,038,187	$1,035,748	$1,033,308	$1,030,869	$1,028,429	$1,025,990	$1,023,551	$1,021,111	$1,018,672	$1,016,232	$1,013,793	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$5,893	$5,882	$5,868	$5,854	$5,841	$5,827	$5,813	$5,799	$5,785	$5,771	$5,758	$5,744	$69,834
b. Debt Component (Line 6 x debt rate) (c)		$1,045	$1,043	$1,040	$1,038	$1,036	$1,033	$1,031	$1,028	$1,026	$1,023	$1,021	$1,018	$12,381
8. Investment Expenses														
a. Depreciation (d)		$2,439	$2,439	$2,439	$2,439	$2,439	$2,439	$2,439	$2,439	$2,439	$2,439	$2,439	$2,439	$29,273
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$9,377	$9,364	$9,348	$9,332	$9,315	$9,299	$9,283	$9,267	$9,250	$9,234	$9,218	$9,202	$111,489

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

Form 42-8E

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
31 - Clean Air Interstate Rule (CAIR) Compliance Peaking														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$55,890,251	$55,888,735	$55,888,735	$55,888,735	$55,888,735	$55,888,735	$55,888,735	$55,888,735	$55,888,735	$55,888,735	$55,888,735	$55,888,735	$55,888,735	
3. Less: Accumulated Depreciation	($21,149,914)	($20,937,570)	($20,724,809)	($20,512,048)	($20,299,287)	($20,086,525)	($19,873,764)	($19,661,003)	($19,448,242)	($19,235,480)	($19,022,719)	($18,809,958)	($18,597,197)	
a. Less: Capital Recovery Unamortized Balance	($46,257)	($45,615)	($44,973)	($44,330)	($43,688)	($43,045)	($42,403)	($41,760)	($41,118)	($40,475)	($39,833)	($39,190)	($38,548)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$77,086,422	$76,871,920	$76,658,516	$76,445,113	$76,231,709	$76,018,305	$75,804,902	$75,591,498	$75,378,094	$75,164,691	$74,951,287	$74,737,883	$74,524,480	
6. Average Net Investment		$76,979,171	$76,765,218	$76,551,814	$76,338,411	$76,125,007	$75,911,603	$75,698,200	$75,484,796	$75,271,392	$75,057,989	$74,844,585	$74,631,181	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$436,134	$434,922	$433,713	$432,504	$431,295	$430,086	$428,877	$427,667	$426,458	$425,249	$424,040	$422,831	$5,153,776
b. Debt Component (Line 6 x debt rate) (c)		$77,326	$77,111	$76,896	$76,682	$76,468	$76,253	$76,039	$75,824	$75,610	$75,396	$75,181	$74,967	$913,753
8. Investment Expenses														
a. Depreciation (d)		$212,761	$212,761	$212,761	$212,761	$212,761	$212,761	$212,761	$212,761	$212,761	$212,761	$212,761	$212,761	$2,553,135
b. Amortization		$642	$642	$642	$642	$642	$642	$642	$642	$642	$642	$642	$642	$7,710
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$726,863	$725,436	$724,013	$722,589	$721,166	$719,742	$718,319	$716,896	$715,472	$714,049	$712,625	$711,202	$8,628,373

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
33 - MATS Project														
Base														
1. Investments														
a. Expenditures/Additions (a)		$0	$1,668	$11	$12	($9)	$0	$0	$0	$0	$0	$0	$0	$1,682
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,687	$1,687
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$109,331,489	$109,331,489	$109,331,489	$109,331,489	$109,331,489	$109,331,489	$109,331,489	$109,331,489	$109,331,489	$109,331,489	$109,331,489	$109,331,489	$109,333,176	
3. Less: Accumulated Depreciation	$30,717,142	$30,971,821	$31,226,500	$31,481,179	$31,735,859	$31,990,538	$32,245,217	$32,499,896	$32,754,575	$33,009,254	$33,263,933	$33,518,612	$33,773,293	
a. Less: Capital Recovery Unamortized Balance	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	
4. CWIP	$4	$4	$1,672	$1,683	$1,695	$1,687	$1,687	$1,687	$1,687	$1,687	$1,687	$1,687	$0	
5. Net Investment (Lines 2 - 3 + 4)	$78,698,418	$78,443,739	$78,190,728	$77,936,060	$77,681,393	$77,426,705	$77,172,026	$76,917,347	$76,662,668	$76,407,989	$76,153,310	$75,898,631	$75,643,950	
6. Average Net Investment		$78,571,078	$78,317,233	$78,063,394	$77,808,726	$77,554,049	$77,299,365	$77,044,686	$76,790,007	$76,535,328	$76,280,649	$76,025,970	$75,771,290	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$445,153	$443,715	$442,277	$440,834	$439,391	$437,948	$436,505	$435,062	$433,619	$432,176	$430,734	$429,291	$5,246,706
b. Debt Component (Line 6 x debt rate) (c)		$78,925	$78,670	$78,415	$78,159	$77,903	$77,647	$77,391	$77,136	$76,880	$76,624	$76,368	$76,112	$930,229
8. Investment Expenses														
a. Depreciation (d)		$254,679	$254,679	$254,679	$254,679	$254,679	$254,679	$254,679	$254,679	$254,679	$254,679	$254,679	$254,681	$3,056,151
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$778,757	$777,064	$775,371	$773,672	$771,973	$770,274	$768,576	$766,877	$765,178	$763,479	$761,781	$760,084	$9,233,085

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

Form 42-8E

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
34 - St Lucie Cooling Water System Inspection & Maintenance														
Base														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3. Less: Accumulated Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$4,449,942	$4,449,942	$4,449,942	$4,449,942	$4,449,942	$4,449,942	$4,449,942	$4,449,942	$4,449,942	$4,449,942	$4,449,942	$4,449,942	$4,449,942	
5. Net Investment (Lines 2 - 3 + 4)	$4,449,942	$4,449,942	$4,449,942	$4,449,942	$4,449,942	$4,449,942	$4,449,942	$4,449,942	$4,449,942	$4,449,942	$4,449,942	$4,449,942	$4,449,942	
6. Average Net Investment		$4,449,942	$4,449,942	$4,449,942	$4,449,942	$4,449,942	$4,449,942	$4,449,942	$4,449,942	$4,449,942	$4,449,942	$4,449,942	$4,449,942	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$25,212	$25,212	$25,212	$25,212	$25,212	$25,212	$25,212	$25,212	$25,212	$25,212	$25,212	$25,212	$302,540
b. Debt Component (Line 6 x debt rate) (c)		$4,470	$4,470	$4,470	$4,470	$4,470	$4,470	$4,470	$4,470	$4,470	$4,470	$4,470	$4,470	$53,640
8. Investment Expenses														
a. Depreciation (d)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$29,682	$29,682	$29,682	$29,682	$29,682	$29,682	$29,682	$29,682	$29,682	$29,682	$29,682	$29,682	$356,179

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

Form 42-8E

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
35 - Martin Plant Drinking Water System Compliance Intermediate														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3. Less: Accumulated Depreciation	($100,891)	($100,891)	($100,891)	($100,891)	($100,891)	($100,891)	($100,891)	($100,891)	($100,891)	($100,891)	($100,891)	($100,891)	($100,891)	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$100,891	$100,891	$100,891	$100,891	$100,891	$100,891	$100,891	$100,891	$100,891	$100,891	$100,891	$100,891	$100,891	
6. Average Net Investment		$100,891	$100,891	$100,891	$100,891	$100,891	$100,891	$100,891	$100,891	$100,891	$100,891	$100,891	$100,891	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$572	$572	$572	$572	$572	$572	$572	$572	$572	$572	$572	$572	$6,859
b. Debt Component (Line 6 x debt rate) (c)		$101	$101	$101	$101	$101	$101	$101	$101	$101	$101	$101	$101	$1,216
8. Investment Expenses														
a. Depreciation (d)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$673	$673	$673	$673	$673	$673	$673	$673	$673	$673	$673	$673	$8,075

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
35 - Martin Plant Drinking Water System Compliance Peaking														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3. Less: Accumulated Depreciation	($76,111)	($76,111)	($76,111)	($76,111)	($76,111)	($76,111)	($76,111)	($76,111)	($76,111)	($76,111)	($76,111)	($76,111)	($76,111)	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$76,111	$76,111	$76,111	$76,111	$76,111	$76,111	$76,111	$76,111	$76,111	$76,111	$76,111	$76,111	$76,111	
6. Average Net Investment		$76,111	$76,111	$76,111	$76,111	$76,111	$76,111	$76,111	$76,111	$76,111	$76,111	$76,111	$76,111	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$431	$431	$431	$431	$431	$431	$431	$431	$431	$431	$431	$431	$5,175
b. Debt Component (Line 6 x debt rate) (c)		$76	$76	$76	$76	$76	$76	$76	$76	$76	$76	$76	$76	$917
8. Investment Expenses														
a. Depreciation (d)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$508	$508	$508	$508	$508	$508	$508	$508	$508	$508	$508	$508	$6,092

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
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January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
36 - Low-Level Radioactive Waste Storage														
Base														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	
3. Less: Accumulated Depreciation	$2,982,053	$3,022,012	$3,061,971	$3,101,930	$3,141,888	$3,181,847	$3,221,806	$3,261,765	$3,301,724	$3,341,682	$3,381,641	$3,421,600	$3,461,559	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$14,474,750	$14,434,792	$14,394,833	$14,354,874	$14,314,915	$14,274,956	$14,234,998	$14,195,039	$14,155,080	$14,115,121	$14,075,162	$14,035,204	$13,995,245	
6. Average Net Investment		$14,454,771	$14,414,812	$14,374,853	$14,334,895	$14,294,936	$14,254,977	$14,215,018	$14,175,059	$14,135,101	$14,095,142	$14,055,183	$14,015,224	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$81,895	$81,669	$81,442	$81,216	$80,990	$80,763	$80,537	$80,310	$80,084	$79,858	$79,631	$79,405	$967,799
b. Debt Component (Line 6 x debt rate) (c)		$14,520	$14,480	$14,440	$14,399	$14,359	$14,319	$14,279	$14,239	$14,199	$14,159	$14,118	$14,078	$171,589
8. Investment Expenses														
a. Depreciation (d)		$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$479,506
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$136,374	$136,107	$135,841	$135,574	$135,308	$135,041	$134,775	$134,508	$134,241	$133,975	$133,708	$133,442	$1,618,894

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
37 - DeSoto Next Generation Solar Energy Center Solar														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$19,208	$15,075	$45,225	$57,285	$0	$0	$0	$0	$136,793
b. Clearings to Plant		$0	$116	$0	$0	$0	$19,208	$0	$117,585	$0	($2,018)	$0	$0	$134,891
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	($2,018)	$0	$0	($2,018)
d. Cost of Removal		$0	$0	$0	$0	($1,431)	$0	$0	$0	$0	$0	$0	$0	($1,431)
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$153,492,429	$153,492,429	$153,492,546	$153,492,546	$153,492,546	$153,492,546	$153,511,753	$153,511,753	$153,629,338	$153,629,338	$153,627,320	$153,627,320	$153,627,320	
3. Less: Accumulated Depreciation	$57,332,110	$57,776,831	$58,221,553	$58,666,275	$59,110,998	$59,554,289	$59,999,040	$60,443,821	$60,888,826	$61,334,057	$61,777,241	$62,222,416	$62,667,591	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$1	$1	$1	$0	$0	$19,208	$15,075	$60,300	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$96,160,320	$95,715,599	$95,270,993	$94,826,271	$94,381,548	$93,957,465	$93,527,788	$93,128,233	$92,740,512	$92,295,281	$91,850,079	$91,404,904	$90,959,730	
6. Average Net Investment		$95,937,959	$95,493,296	$95,048,632	$94,603,909	$94,169,506	$93,742,626	$93,328,010	$92,934,372	$92,517,897	$92,072,680	$91,627,491	$91,182,317	
a. Average ITC Balance		$27,525,993	$27,403,927	$27,281,861	$27,159,795	$27,037,729	$26,915,663	$26,793,597	$26,671,531	$26,549,465	$26,427,399	$26,305,333	$26,183,267	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$581,898	$579,208	$576,519	$573,829	$571,198	$568,610	$566,090	$563,690	$561,160	$558,468	$555,776	$553,083	$6,809,530
b. Debt Component (Line 6 x debt rate) (c)		$102,409	$101,935	$101,462	$100,988	$100,525	$100,070	$99,627	$99,204	$98,759	$98,285	$97,811	$97,337	$1,198,414
8. Investment Expenses														
a. Depreciation (d)		$432,534	$432,535	$432,535	$432,535	$432,535	$432,564	$432,594	$432,819	$433,044	$433,016	$432,988	$432,988	$5,192,686
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$146,244
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. ITC Solar		($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($1,924,740)
9. Total System Recoverable Expenses (Lines 7 + 8)		$968,633	$965,470	$962,308	$959,145	$956,051	$953,036	$950,102	$947,505	$944,755	$941,561	$938,366	$935,200	$11,422,133

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
38 - Space Coast Next Generation Solar Energy Center Solar														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$1,005	$1,005	$1,005	$1,005	$1,005	$1,005	$2,010	$8,040
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$2,010	$1,005	$1,005	$1,005	$1,005	$2,010	$8,040
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$70,557,314	$70,557,314	$70,557,314	$70,557,314	$70,557,314	$70,557,314	$70,557,314	$70,559,324	$70,560,329	$70,561,334	$70,562,339	$70,563,344	$70,565,354	
3. Less: Accumulated Depreciation	$25,417,036	$25,616,364	$25,815,692	$26,015,019	$26,214,347	$26,413,675	$26,613,002	$26,812,332	$27,011,667	$27,211,004	$27,410,344	$27,609,686	$27,809,033	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$1,005	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$45,140,278	$44,940,950	$44,741,623	$44,542,295	$44,342,967	$44,143,639	$43,945,317	$43,746,992	$43,548,663	$43,350,331	$43,151,996	$42,953,658	$42,756,321	
6. Average Net Investment		$45,040,614	$44,841,287	$44,641,959	$44,442,631	$44,243,303	$44,044,478	$43,846,154	$43,647,827	$43,449,497	$43,251,163	$43,052,827	$42,854,990	
a. Average ITC Balance		$11,824,527	$11,773,338	$11,722,149	$11,670,960	$11,619,771	$11,568,582	$11,517,393	$11,466,204	$11,415,015	$11,363,826	$11,312,637	$11,261,448	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$271,657	$270,456	$269,256	$268,055	$266,855	$265,657	$264,462	$263,267	$262,072	$260,877	$259,682	$258,490	$3,180,785
b. Debt Component (Line 6 x debt rate) (c)		$47,838	$47,626	$47,415	$47,203	$46,992	$46,781	$46,570	$46,360	$46,149	$45,939	$45,729	$45,519	$560,120
8. Investment Expenses														
a. Depreciation (d)		$194,936	$194,936	$194,936	$194,936	$194,936	$194,935	$194,938	$194,942	$194,945	$194,948	$194,951	$194,955	$2,339,293
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$52,704
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. ITC Solar		($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($807,156)
9. Total System Recoverable Expenses (Lines 7 + 8)		$451,559	$450,147	$448,735	$447,323	$445,911	$444,502	$443,099	$441,698	$440,295	$438,893	$437,490	$436,092	$5,325,746

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
39 - Martin Next Generation Solar Energy Center Intermediate														
1. Investments														
a. Expenditures/Additions (a)		$236,806	($1,402,570)	$339,015	($434,309)	$58,581	$145,725	$5,025	$0	$0	$5,025	$0	$0	($1,046,702)
b. Clearings to Plant		$45,743	$675,462	$4,182	$124,352	($2,752)	$0	$0	$0	$0	$10,050	$0	$0	$857,038
c. Retirements		($6,985)	($1,177,855)	$0	($374,415)	$0	$0	$0	$0	$0	$0	$0	$0	($1,559,256)
d. Cost of Removal		($45,195)	($3,015)	($24,640)	($17,713)	($12,899)	$0	$0	$0	$0	$0	$0	$0	($103,462)
e. Salvage		$59,062	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$59,062
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$427,118,948	$427,164,691	$427,840,153	$427,844,335	$427,968,687	$427,965,936	$427,965,936	$427,965,936	$427,965,936	$427,965,936	$427,975,986	$427,975,986	$427,975,986	
3. Less: Accumulated Depreciation	$125,173,264	$126,258,430	$126,156,675	$127,211,967	$127,899,924	$128,967,256	$130,047,484	$131,127,712	$132,207,940	$133,288,168	$134,368,408	$135,448,661	$136,528,913	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$1,774,599	$2,011,405	$608,835	$947,850	$513,541	$572,122	$717,847	$722,872	$722,872	$722,872	$717,847	$717,847	$717,847	
5. Net Investment (Lines 2 - 3 + 4)	$303,720,282	$302,917,666	$302,292,313	$301,580,218	$300,582,305	$299,570,802	$298,636,299	$297,561,096	$296,480,868	$295,400,639	$294,325,424	$293,245,172	$292,164,920	
6. Average Net Investment		$303,318,974	$302,604,990	$301,936,266	$301,081,262	$300,076,553	$299,103,550	$298,098,697	$297,020,982	$295,940,754	$294,863,032	$293,785,298	$292,705,046	
a. Average ITC Balance		$82,095,625	$81,751,827	$81,408,029	$81,064,231	$80,720,433	$80,376,635	$80,032,837	$79,689,039	$79,345,241	$79,001,443	$78,657,645	$78,313,847	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$1,832,867	$1,828,343	$1,824,075	$1,818,752	$1,812,581	$1,806,589	$1,800,417	$1,793,832	$1,787,233	$1,780,648	$1,774,063	$1,767,464	$21,626,864
b. Debt Component (Line 6 x debt rate) (c)		$322,696	$321,903	$321,156	$320,222	$319,137	$318,084	$316,999	$315,841	$314,681	$313,523	$312,365	$311,204	$3,807,811
8. Investment Expenses														
a. Depreciation (d)		$1,028,729	$1,029,561	$1,030,376	$1,030,530	$1,030,676	$1,030,673	$1,030,673	$1,030,673	$1,030,673	$1,030,685	$1,030,697	$1,030,697	$12,364,644
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$594,660
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. ITC Solar		($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($5,421,012)
9. Total System Recoverable Expenses (Lines 7 + 8)		$2,782,095	$2,777,610	$2,773,411	$2,767,308	$2,760,198	$2,753,150	$2,745,893	$2,738,151	$2,730,391	$2,722,660	$2,714,929	$2,707,169	$32,972,967

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
41 - Manatee Temporary Heating System														
Distribution														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		($155)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($155)
c. Retirements		($155)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($155)
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$1,417,015	$1,416,860	$1,416,860	$1,416,860	$1,416,860	$1,416,860	$1,416,860	$1,416,860	$1,416,860	$1,416,860	$1,416,860	$1,416,860	$1,416,860	
3. Less: Accumulated Depreciation	$1,189,310	$1,189,155	$1,189,155	$1,189,155	$1,189,155	$1,189,155	$1,189,155	$1,189,155	$1,189,155	$1,189,155	$1,189,155	$1,189,155	$1,189,155	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	
6. Average Net Investment		$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$1,290	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290	$1,290	$15,481
b. Debt Component (Line 6 x debt rate) (c)		$229	$229	$229	$229	$229	$229	$229	$229	$229	$229	$229	$229	$2,745
8. Investment Expenses														
a. Depreciation (d)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$1,519	$1,519	$1,519	$1,519	$1,519	$1,519	$1,519	$1,519	$1,519	$1,519	$1,519	$1,519	$18,226

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
41 - Manatee Temporary Heating System Intermediate														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$887	$0	$833	($4,440,611)	$4,441,225	$0	$0	$0	$0	$0	$0	$0	$2,333
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$50,465	$0	$0	$0	$0	$0	$0	$0	$50,465
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$17,573,949	$17,574,836	$17,574,836	$17,575,669	$13,135,058	$17,576,282	$17,576,282	$17,576,282	$17,576,282	$17,576,282	$17,576,282	$17,576,282	$17,576,282	
3. Less: Accumulated Depreciation	$6,653,173	$6,849,520	$7,045,877	$7,242,244	$7,388,159	$7,635,012	$7,831,402	$8,027,792	$8,224,182	$8,420,573	$8,616,963	$8,813,353	$9,009,743	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$10,920,776	$10,725,316	$10,528,959	$10,333,425	$5,746,899	$9,941,271	$9,744,881	$9,548,490	$9,352,100	$9,155,710	$8,959,320	$8,762,929	$8,566,539	
6. Average Net Investment		$10,823,046	$10,627,138	$10,431,192	$8,040,162	$7,844,085	$9,843,076	$9,646,685	$9,450,295	$9,253,905	$9,057,515	$8,861,124	$8,664,734	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$61,319	$60,209	$59,099	$45,552	$44,442	$55,767	$54,654	$53,542	$52,429	$51,316	$50,204	$49,091	$637,625
b. Debt Component (Line 6 x debt rate) (c)		$10,872	$10,675	$10,478	$8,076	$7,879	$9,887	$9,690	$9,493	$9,296	$9,098	$8,901	$8,704	$113,049
8. Investment Expenses														
a. Depreciation (d)		$196,347	$196,357	$196,367	$145,915	$196,387	$196,390	$196,390	$196,390	$196,390	$196,390	$196,390	$196,390	$2,306,105
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$268,538	$267,242	$265,944	$199,544	$248,708	$262,045	$260,735	$259,425	$258,115	$256,805	$255,495	$254,185	$3,056,779

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
41 - Manatee Temporary Heating System														
Peaking														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$4,440,611	($4,440,611)	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	($50,465)	$0	$0	$0	$0	$0	$0	$0	($50,465)
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$0	$0	$0	$0	$4,440,611	$0	$0	$0	$0	$0	$0	$0	$0	
3. Less: Accumulated Depreciation	$0	($0)	($0)	($0)	$50,461	($8)	($8)	($8)	($8)	($8)	($8)	($8)	($8)	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$4,390,150	$8	$8	$8	$8	$8	$8	$8	$8	
6. Average Net Investment		$0	$0	$0	$2,195,075	$2,195,079	$8	$8	$8	$8	$8	$8	$8	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$0	$0	$0	$12,436	$12,436	$0	$0	$0	$0	$0	$0	$0	$24,873
b. Debt Component (Line 6 x debt rate) (c)		$0	$0	$0	$2,205	$2,205	$0	$0	$0	$0	$0	$0	$0	$4,410
8. Investment Expenses														
a. Depreciation (d)		$0	$0	$0	$50,461	($4)	$0	$0	$0	$0	$0	$0	$0	$50,458
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$0	$0	$0	$65,103	$14,638	$0	$0	$0	$0	$0	$0	$0	$79,741

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2) Beginning of Period	(3) a-Jan - 2021	(4) a-Feb - 2021	(5) a-Mar - 2021	(6) a-Apr - 2021	(7) a-May - 2021	(8) Jun - 2021	(9) Jul - 2021	(10) Aug - 2021	(11) Sep - 2021	(12) Oct - 2021	(13) Nov - 2021	(14) Dec - 2021	(15) Total
41 - Manatee Temporary Heating System Transmission														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	
3. Less: Accumulated Depreciation	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
6. Average Net Investment		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Debt Component (Line 6 x debt rate) (c)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8. Investment Expenses														
a. Depreciation (d)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
42 - Turkey Point Cooling Canal Monitoring Plan														
Base														
1. Investments														
a. Expenditures/Additions (a)		$89,572	$52,275	$199,209	$539,783	$1,206,315	$1,344,223	$759,252	$739,899	$857,490	$167,157	$140,497	$161,774	$6,257,446
b. Clearings to Plant		$12,435	($3,096)	($4,311)	$0	$0	$0	$0	$1,719,653	$0	$0	$0	$3,582,199	$5,306,879
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$203,127	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$203,127
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$63,896,975	$63,909,410	$63,906,314	$63,902,003	$63,902,003	$63,902,003	$63,902,003	$63,902,003	$65,621,656	$65,621,656	$65,621,656	$65,621,656	$69,203,854	
3. Less: Accumulated Depreciation	$4,697,694	$5,075,628	$5,250,447	$5,425,257	$5,600,061	$5,774,865	$5,949,669	$6,124,472	$6,301,519	$6,480,808	$6,660,098	$6,839,387	$7,023,348	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$394,497	$484,069	$536,344	$735,553	$1,275,336	$2,481,651	$3,825,874	$4,585,126	$3,605,372	$4,462,862	$4,630,019	$4,770,516	$1,350,091	
5. Net Investment (Lines 2 - 3 + 4)	$59,593,778	$59,317,851	$59,192,210	$59,212,299	$59,577,278	$60,608,789	$61,778,208	$62,362,656	$62,925,509	$63,603,709	$63,591,577	$63,552,785	$63,530,598	
6. Average Net Investment		$59,455,815	$59,255,031	$59,202,255	$59,394,788	$60,093,033	$61,193,499	$62,070,432	$62,644,083	$63,264,609	$63,597,643	$63,572,181	$63,541,691	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$336,854	$335,716	$335,417	$336,508	$340,464	$346,699	$351,667	$354,917	$358,433	$360,320	$360,175	$360,002	$4,177,170
b. Debt Component (Line 6 x debt rate) (c)		$59,723	$59,522	$59,469	$59,662	$60,363	$61,469	$62,350	$62,926	$63,549	$63,884	$63,858	$63,828	$740,603
8. Investment Expenses														
a. Depreciation (d)		$174,807	$174,819	$174,810	$174,804	$174,804	$174,804	$174,804	$177,047	$179,289	$179,289	$179,289	$183,961	$2,122,527
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$571,384	$570,057	$569,695	$570,974	$575,631	$582,971	$588,821	$594,890	$601,271	$603,493	$603,323	$607,791	$7,040,300

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
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Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
42 - Turkey Point Cooling Canal Monitoring Plan Intermediate														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		($203,127)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($203,127)
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3. Less: Accumulated Depreciation	$203,127	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	($203,127)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
6. Average Net Investment		($101,563)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		($575)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($575)
b. Debt Component (Line 6 x debt rate) (c)		($102)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($102)
8. Investment Expenses														
a. Depreciation (d)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		($677)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($677)

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
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Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
44 - Martin Plant Barley Barber Swamp Iron Mitigation Intermediate														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	
3. Less: Accumulated Depreciation	$20,359	$20,556	$20,754	$20,951	$21,148	$21,345	$21,542	$21,740	$21,937	$22,134	$22,331	$22,528	$22,725	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$73,530	$73,333	$73,136	$72,939	$72,742	$72,544	$72,347	$72,150	$71,953	$71,756	$71,559	$71,361	$71,164	
6. Average Net Investment		$73,432	$73,235	$73,037	$72,840	$72,643	$72,446	$72,249	$72,051	$71,854	$71,657	$71,460	$71,263	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$416	$415	$414	$413	$412	$410	$409	$408	$407	$406	$405	$404	$4,919
b. Debt Component (Line 6 x debt rate) (c)		$74	$74	$73	$73	$73	$73	$73	$72	$72	$72	$72	$72	$872
8. Investment Expenses														
a. Depreciation (d)		$197	$197	$197	$197	$197	$197	$197	$197	$197	$197	$197	$197	$2,366
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$687	$686	$684	$683	$682	$680	$679	$678	$676	$675	$674	$673	$8,157

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

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Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
44 - Martin Plant Barley Barber Swamp Iron Mitigation Peaking														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	
3. Less: Accumulated Depreciation	$15,359	$15,508	$15,656	$15,805	$15,954	$16,102	$16,251	$16,400	$16,549	$16,697	$16,846	$16,995	$17,144	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$55,470	$55,321	$55,173	$55,024	$54,875	$54,726	$54,578	$54,429	$54,280	$54,132	$53,983	$53,834	$53,685	
6. Average Net Investment		$55,396	$55,247	$55,098	$54,950	$54,801	$54,652	$54,503	$54,355	$54,206	$54,057	$53,908	$53,760	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$314	$313	$312	$311	$310	$310	$309	$308	$307	$306	$305	$305	$3,711
b. Debt Component (Line 6 x debt rate) (c)		$56	$55	$55	$55	$55	$55	$55	$55	$54	$54	$54	$54	$658
8. Investment Expenses														
a. Depreciation (d)		$149	$149	$149	$149	$149	$149	$149	$149	$149	$149	$149	$149	$1,785
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$518	$517	$516	$515	$514	$513	$512	$511	$510	$509	$508	$507	$6,153

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
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Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
45 - 800 MW Unit ESP														
Intermediate														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$63,759	$66,041	$66,041	$66,041	$66,041	$66,041	$66,041	$66,041	$66,041	$66,041	$66,041	$66,041	$66,041	
3. Less: Accumulated Depreciation	$21,340	$22,524	$22,943	$23,362	$23,782	$24,201	$24,621	$25,040	$25,459	$25,879	$26,298	$26,717	$27,137	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$42,418	$43,517	$43,098	$42,678	$42,259	$41,840	$41,420	$41,001	$40,582	$40,162	$39,743	$39,323	$38,904	
6. Average Net Investment		$42,968	$43,307	$42,888	$42,469	$42,049	$41,630	$41,211	$40,791	$40,372	$39,953	$39,533	$39,114	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$243	$245	$243	$241	$238	$236	$233	$231	$229	$226	$224	$222	$2,812
b. Debt Component (Line 6 x debt rate) (c)		$43	$44	$43	$43	$42	$42	$41	$41	$41	$40	$40	$39	$499
8. Investment Expenses														
a. Depreciation (d)		$419	$419	$419	$419	$419	$419	$419	$419	$419	$419	$419	$419	$5,032
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$706	$708	$705	$703	$700	$697	$694	$691	$689	$686	$683	$680	$8,343

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
45 - 800 MW Unit ESP														
Peaking														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$6,720	($6,720)	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	($8,365)	$14,567	$0	$0	$0	$0	$0	$0	$0	$6,202
c. Retirements		$0	$0	$0	($15,085)	$0	$0	$0	$0	$0	$0	$0	$0	($15,085)
d. Cost of Removal		$0	$0	$0	$0	($1,299)	$0	$0	$0	$0	$0	$0	$0	($1,299)
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$108,369,392	$108,367,110	$108,367,110	$108,367,110	$108,358,745	$108,373,312	$108,373,312	$108,373,312	$108,373,312	$108,373,312	$108,373,312	$108,373,312	$108,373,312	
3. Less: Accumulated Depreciation	($60,048,303)	($59,617,694)	($59,186,321)	($58,754,947)	($58,338,677)	($57,908,607)	($57,477,208)	($57,045,809)	($56,614,410)	($56,183,011)	($55,751,612)	($55,320,213)	($54,888,814)	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$6,720	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$168,417,695	$167,984,803	$167,553,430	$167,128,777	$166,697,422	$166,281,918	$165,850,520	$165,419,121	$164,987,722	$164,556,323	$164,124,924	$163,693,525	$163,262,126	
6. Average Net Investment		$168,201,249	$167,769,117	$167,341,104	$166,913,099	$166,489,670	$166,066,219	$165,634,820	$165,203,421	$164,772,022	$164,340,623	$163,909,224	$163,477,826	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$952,963	$950,515	$948,090	$945,665	$943,266	$940,867	$938,422	$935,978	$933,534	$931,090	$928,646	$926,202	$11,275,236
b. Debt Component (Line 6 x debt rate) (c)		$168,958	$168,524	$168,094	$167,664	$167,239	$166,814	$166,380	$165,947	$165,513	$165,080	$164,647	$164,213	$1,999,074
8. Investment Expenses														
a. Depreciation (d)		$431,373	$431,373	$431,373	$431,356	$431,369	$431,399	$431,399	$431,399	$431,399	$431,399	$431,399	$431,399	$5,176,636
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$1,553,294	$1,550,412	$1,547,557	$1,544,685	$1,541,873	$1,539,079	$1,536,202	$1,533,324	$1,530,447	$1,527,569	$1,524,692	$1,521,814	$18,450,946

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
47 - NPDES Permit Renewal Requirements														
Base														
1. Investments														
a. Expenditures/Additions (a)		$72,689	$16,920	$215,126	$122,926	$31,162	$702,943	$441,859	$49,523	$45,120	$1,790,191	$4,240	$2,395	$3,495,094
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$2,801,208	$0	$0	$0	$0	$2,801,208
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		($0)	$0	($0)	($0)	$0	$0	$0	$0	$0	$0	$0	$0	($0)
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$0	$0	$0	$0	$0	$0	$0	$0	$2,801,208	$2,801,208	$2,801,208	$2,801,208	$2,801,208	
3. Less: Accumulated Depreciation	($3)	($3)	($3)	($3)	($3)	($3)	($3)	($3)	$8,424	$25,278	$42,132	$58,985	$75,839	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$2,342,385	$2,415,075	$2,431,994	$2,647,120	$2,770,046	$2,801,208	$3,504,151	$3,946,010	$1,194,325	$1,239,445	$3,029,636	$3,033,876	$3,036,271	
5. Net Investment (Lines 2 - 3 + 4)	$2,342,388	$2,415,077	$2,431,997	$2,647,124	$2,770,050	$2,801,211	$3,504,154	$3,946,013	$3,987,109	$4,015,375	$5,788,712	$5,776,098	$5,761,639	
6. Average Net Investment		$2,378,733	$2,423,537	$2,539,560	$2,708,587	$2,785,630	$3,152,683	$3,725,084	$3,966,561	$4,001,242	$4,902,044	$5,782,405	$5,768,869	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$13,477	$13,731	$14,388	$15,346	$15,782	$17,862	$21,105	$22,473	$22,669	$27,773	$32,761	$32,684	$250,051
b. Debt Component (Line 6 x debt rate) (c)		$2,389	$2,434	$2,551	$2,721	$2,798	$3,167	$3,742	$3,984	$4,019	$4,924	$5,808	$5,795	$44,334
8. Investment Expenses														
a. Depreciation (d)		$0	$0	$0	$0	$0	$0	$0	$8,427	$16,854	$16,854	$16,854	$16,854	$75,843
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$15,866	$16,165	$16,939	$18,067	$18,580	$21,029	$24,847	$34,884	$43,543	$49,551	$55,423	$55,333	$370,228

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
50 - Steam Electric Effluent Guidelines Revised Rules Base														
1. Investments														
a. Expenditures/Additions (a)		$365,274	$4,227	$5,217	$29,242	($1,239,932)	$50,250	$50,250	$50,250	$50,250	$50,250	$50,250	$50,250	($484,221)
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3. Less: Accumulated Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$1,664,051	$2,029,325	$2,033,553	$2,038,770	$2,068,012	$828,080	$878,330	$928,580	$978,830	$1,029,080	$1,079,330	$1,129,580	$1,179,830	
5. Net Investment (Lines 2 - 3 + 4)	$1,664,051	$2,029,325	$2,033,553	$2,038,770	$2,068,012	$828,080	$878,330	$928,580	$978,830	$1,029,080	$1,079,330	$1,129,580	$1,179,830	
6. Average Net Investment		$1,846,688	$2,031,439	$2,036,162	$2,053,391	$1,448,046	$853,205	$903,455	$953,705	$1,003,955	$1,054,205	$1,104,455	$1,154,705	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$10,463	$11,509	$11,536	$11,634	$8,204	$4,834	$5,119	$5,403	$5,688	$5,973	$6,257	$6,542	$93,162
b. Debt Component (Line 6 x debt rate) (c)		$1,855	$2,041	$2,045	$2,063	$1,455	$857	$908	$958	$1,008	$1,059	$1,109	$1,160	$16,517
8. Investment Expenses														
a. Depreciation (d)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$12,318	$13,550	$13,581	$13,696	$9,659	$5,691	$6,026	$6,361	$6,696	$7,032	$7,367	$7,702	$109,679

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
54 - Coal Combustion Residuals														
Base														
1. Investments														
a. Expenditures/Additions (a)		$0	$184,994	$67,686	$228,985	$11,446	$14,549	$14,549	$14,549	$14,549	$14,549	$14,549	$14,549	$594,954
b. Clearings to Plant		$1,796,067	$2,750	$2,500	$2,313	$2,125	$0	$0	$0	$0	$0	$0	$594,954	$2,400,709
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$109,696,378	$111,492,445	$111,495,195	$111,497,695	$111,500,008	$111,502,133	$111,502,133	$111,502,133	$111,502,133	$111,502,133	$111,502,133	$111,502,133	$112,097,087	
3. Less: Accumulated Depreciation	$3,719,947	$3,969,511	$4,221,166	$4,472,825	$4,724,489	$4,976,158	$5,227,828	$5,479,499	$5,731,169	$5,982,840	$6,234,510	$6,486,181	$6,738,543	
a. Less: Capital Recovery Unamortized Balance	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	
4. CWIP	$0	$0	$184,994	$252,680	$481,665	$493,111	$507,660	$522,209	$536,758	$551,307	$565,856	$580,405	$0	
5. Net Investment (Lines 2 - 3 + 4)	$106,031,681	$107,578,184	$107,514,273	$107,332,800	$107,312,433	$107,074,336	$106,837,214	$106,600,093	$106,362,971	$106,125,850	$105,888,728	$105,651,606	$105,413,794	
6. Average Net Investment		$106,804,933	$107,546,229	$107,423,537	$107,322,617	$107,193,385	$106,955,775	$106,718,653	$106,481,532	$106,244,410	$106,007,289	$105,770,167	$105,532,700	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$605,115	$609,315	$608,620	$608,048	$607,316	$605,970	$604,626	$603,283	$601,939	$600,596	$599,253	$597,907	$7,251,989
b. Debt Component (Line 6 x debt rate) (c)		$107,286	$108,030	$107,907	$107,806	$107,676	$107,437	$107,199	$106,961	$106,723	$106,484	$106,246	$106,008	$1,285,761
8. Investment Expenses														
a. Depreciation (d)		$249,564	$251,654	$251,660	$251,664	$251,668	$251,671	$251,671	$251,671	$251,671	$251,671	$251,671	$252,362	$3,018,596
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$961,965	$969,000	$968,186	$967,518	$966,660	$965,077	$963,496	$961,914	$960,333	$958,751	$957,169	$956,277	$11,556,346

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
123 - The Protected Species Project														
Intermediate														
1. Investments														
a. Expenditures/Additions (a)		($3,012)	$0	$0	$0	$0	$0	$30,150	$0	$172,543	$0	$0	$0	$199,681
b. Clearings to Plant		$125,703	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$125,703
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$0	$125,703	$125,703	$125,703	$125,703	$125,703	$125,703	$125,703	$125,703	$125,703	$125,703	$125,703	$125,703	
3. Less: Accumulated Depreciation	$0	$0	$310	$775	$1,085	$1,395	$1,705	$2,015	$2,326	$2,636	$2,946	$3,256	$3,566	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$3,012	$0	$0	$0	$0	$0	$0	$30,150	$30,150	$202,693	$202,693	$202,693	$202,693	
5. Net Investment (Lines 2 - 3 + 4)	$3,012	$125,703	$125,393	$124,928	$124,618	$124,307	$123,997	$153,837	$153,527	$325,760	$325,450	$325,140	$324,830	
6. Average Net Investment		$64,357	$125,548	$125,160	$124,773	$124,462	$124,152	$138,917	$153,682	$239,644	$325,605	$325,295	$324,985	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$365	$711	$709	$707	$705	$703	$787	$871	$1,358	$1,845	$1,843	$1,841	$12,445
b. Debt Component (Line 6 x debt rate) (c)		$65	$126	$126	$125	$125	$125	$140	$154	$241	$327	$327	$326	$2,206
8. Investment Expenses														
a. Depreciation (d)		$0	$310	$465	$310	$310	$310	$310	$310	$310	$310	$310	$310	$3,566
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$429	$1,147	$1,300	$1,142	$1,140	$1,138	$1,237	$1,335	$1,909	$2,482	$2,480	$2,478	$18,217

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
124 - FPL Miami-Dade Clean Water Recovery Center Intermediate														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$360,000	$485,000	$555,000	$569,000	$675,000	$2,644,000
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3. Less: Accumulated Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$360,000	$845,000	$1,400,000	$1,969,000	$2,644,000	
5. Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	$0	$360,000	$845,000	$1,400,000	$1,969,000	$2,644,000	
6. Average Net Investment		$0	$0	$0	$0	$0	$0	$0	$180,000	$602,500	$1,122,500	$1,684,500	$2,306,500	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up		$0	$0	$0	$0	$0	$0	$0	$1,020	$3,414	$6,360	$9,544	$13,068	$33,404
b. Debt Component (Line 6 x debt rate) (c)		$0	$0	$0	$0	$0	$0	$0	$181	$605	$1,128	$1,692	$2,317	$5,923
8. Investment Expenses														
a. Depreciation (d)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$0	$0	$0	$0	$0	$0	$0	$1,201	$4,019	$7,487	$11,236	$15,385	$39,327

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 71-73.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 71-73.
(f) Applicable amortization period(s). See Form 42-8E, pages 71-73.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.393% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.469% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Actual/Estimated
Return On Capital Investments, Depreciation and Taxes

January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	a-Jan - 2021	a-Feb - 2021	a-Mar - 2021	a-Apr - 2021	a-May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
1. Investments														
a. Purchases/Transfers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Sales/Transfers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Auction Proceeds/Others	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Working Capital - Dr (Cr)														
a. 158.100 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
b. 158.200 Allowances Withheld	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
c. 182.300 Other Regulatory Assets - Losses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
d. 254.900 Other Regulatory Liabilities - Gains	($144)	($144)	($144)	($122)	($122)	($122)	($144)	($144)	($144)	($167)	($167)	($167)	($189)	
3. Total Working Capital	($144)	($144)	($144)	($122)	($122)	($122)	($144)	($144)	($144)	($167)	($167)	($167)	($189)	
4. Average Total Working Capital Balance		($144)	($144)	($133)	($122)	($122)	($133)	($144)	($144)	($156)	($167)	($167)	($178)	
5. Return on Average Total Working Capital Balance														
a. Equity Component (Line 4 x equity rate grossed up for taxes)		($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($10)
b. Debt Component (Line 4 x debt rate)		($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($2)
6. Total Return Component (a)		($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($12)
7. Expenses														
a. 411.800 Gains from Dispositions of Allowances		$0	$0	($21)	$0	$0	$22	$0	$0	$22	$0	$0	$22	$47
b. 411.900 Losses from Dispositions of Allowances		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. 509.000 Allowance Expense		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8. Net Expenses (Lines 7a + 7b + 7c)		$0	$0	($21)	$0	$0	$22	$0	$0	$22	$0	$0	$22	$47
9. Total System Recoverable Expenses (Lines 6 + 8)		($1)	($1)	($22)	($1)	($1)	$22	($1)	($1)	$21	($1)	($1)	$21	$35

Notes:
(a) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1316% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(b) The Debt Component for the Jan. – Dec. 2021 period is 1.2054% is based on the 2021 Forecasted Surveillance Report.
(c) Line 5 is reported on Capital Schedule
(d) Line 7 is reported on O&M Schedule

Florida Power & Light Company
Environmental Cost Recovery Clause
2021 Annual Capital Depreciation Schedule

FORM 42-8E

Project	Function	Unit	Utility	DEPR RATE	12/1/2020	12/1/2021
002-LOW NOX BURNER TECHNOLOGY	02 - Steam Generation Plant	Turkey Pt U1	31200	0.00%	-	-
002-LOW NOX BURNER TECHNOLOGY Total					**-**	**-**
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	CapeCanaveral U1	31200	0.00%	-	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee Comm	31200	7.62%	65,605	65,605
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee U1	31100	1.74%	56,430	56,430
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee U1	31200	4.64%	424,505	424,505
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee U2	31100	1.83%	56,333	56,333
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee U2	31200	4.99%	468,728	468,728
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin Comm	31200	4.45%	-	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin Comm	31650	20.00%	-	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin Comm	31670	14.29%	-	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin U1	31100	2.68%	-	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin U1	31200	4.53%	-	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin U2	31100	2.39%	-	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin U2	31200	4.64%	-	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Scherer U4	31200	2.79%	515,653	515,653
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	SJRPP - Comm	31100	1.09%	-	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	SJRPP - Comm	31200	1.44%	-	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Turkey Pt Comm	31100	0.00%	-	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Turkey Pt Comm	31200	0.00%	-	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Turkey Pt U1	31100	0.00%	-	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Turkey Pt U1	31200	0.00%	-	-
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtLauderdale Comm	34100	2.20%	-	-
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtLauderdale Comm	34500	1.60%	-	-
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtLauderdale GTs	34300	8.25%	10,225	10,225
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtLauderdale U4	34300	4.11%	-	-
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtLauderdale U5	34300	5.00%	-	-
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtMyers U2	34100	2.34%	-	-
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtMyers U2	34300	3.46%	365,000	365,000
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtMyers U3	34100	3.38%	6,098	6,098
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtMyers U3	34300	4.54%	71,939	71,939
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtMyers U3 SC Peaker	34300	3.04%	69,082	69,082
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Manatee U3	34300	3.35%	87,691	87,691
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Martin U3	34300	4.49%	615,469	615,469
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Martin U4	34300	3.92%	598,036	598,036
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Putnam Comm	34100	0.00%	-	-
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Putnam Comm	34300	0.00%	-	-
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Sanford Comm	34300	0.00%	-	-
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Sanford U4	34300	4.00%	310,021	310,021
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Sanford U5	34300	4.12%	273,035	273,035
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Martin U8	34300	3.37%	13,693	13,693
003-CONTINUOUS EMISSION MONITORING Total					**4,007,544**	**4,007,544**
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Manatee Comm	31100	3.17%	3,111,263	3,111,263
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Manatee Comm	31200	7.62%	174,543	174,543
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Manatee U1	31200	4.64%	104,845	104,845
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Manatee U2	31200	4.99%	127,429	127,429
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Martin Comm	31100	2.52%	65,093	65,093
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Martin Comm	31200	4.45%	-	-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Martin U1	31100	2.68%	-	-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Martin U2	31100	2.39%	-	-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	SJRPP - Comm	31100	1.09%	-	-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	SJRPP - Comm	31200	1.44%	-	-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Turkey Pt Comm	31100	0.00%	-	-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Turkey Pt U1	31100	0.00%	-	-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	FtLauderdale Comm	34200	3.09%	898,111	898,111
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	FtLauderdale GTs	34200	4.73%	584,290	584,290
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	FtMyers GTs	34200	7.84%	133,479	133,479
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	FtMyers U3	34200	3.58%	18,616	18,616
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	Martin Comm	34200	2.42%	455,941	455,941
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	PtEverglades GTs	34200	0.00%	-	-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	Putnam Comm	34200	0.00%	-	-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	08 - General Plant	General Plant	39000	1.50%	5,837,840	8,225,223
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS Total					**11,511,450**	**13,898,833**
007-RELOCATE TURBINE LUBE OIL PIPING	03 - Nuclear Generation Plant	StLucie U1	32300	5.11%	31,030	31,030
007-RELOCATE TURBINE LUBE OIL PIPING Total					**31,030**	**31,030**
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Manatee Comm	31100	3.17%	46,882	46,882
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Manatee Comm	31650	20.00%	-	-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Manatee Comm	31670	14.29%	-	-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Manatee U1	31100	1.74%		51,165
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Martin Comm	31600	3.79%	-	-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Martin Comm	31650	20.00%	227,249	280,886
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Martin Comm	31670	14.29%	253,877	157,547
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Turkey Pt Comm	31100	0.00%	-	-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Turkey Pt Comm	31650	20.00%	-	-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	CapeCanaveral U1CC	34100	2.69%	128,024	5,334
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	CapeCanaveral U1CC	34650	20.00%	-	-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	CapeCanaveral U1CC	34670	14.29%	-	-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	FtLauderdale Comm	34100	2.20%	358,605	358,605
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	FtMyers Comm	34650	20.00%	-	-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	FtMyers U2	34100	2.34%		558,534
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	PtEverglades U5	34100	2.64%	22,550	22,550
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	Putnam Comm	34650	20.00%	-	-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	Riviera Comm	34650	20.00%	-	-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	Sanford Comm	34100	2.40%	15,922	15,922
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	07 - Distribution Plant - Electric	Mass Distribution Plant	36670	2.00%	2,995	2,995
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	08 - General Plant	General Plant	39000	1.50%	4,413	4,413
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	08 - General Plant	General Plant	39190	33.33%	-	-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT Total					**1,060,517**	**1,504,834**
010-REROUTE STORMWATER RUNOFF	03 - Nuclear Generation Plant	StLucie Comm	32100	2.25%	117,794	117,794
010-REROUTE STORMWATER RUNOFF Total					**117,794**	**117,794**
012-SCHERER DISCHARGE PIPELINE	02 - Steam Generation Plant	Scherer Comm	31100	1.51%	524,873	524,873
012-SCHERER DISCHARGE PIPELINE	02 - Steam Generation Plant	Scherer Comm	31200	2.23%	328,762	328,762
012-SCHERER DISCHARGE PIPELINE	02 - Steam Generation Plant	Scherer Comm	31400	2.08%	689	689
012-SCHERER DISCHARGE PIPELINE Total					**854,324**	**854,324**
016-ST.LUCIE TURTLE NETS	03 - Nuclear Generation Plant	StLucie Comm	32100	2.25%	6,909,559	6,909,559
016-ST.LUCIE TURTLE NETS Total					**6,909,559**	**6,909,559**
020-WASTEWATER/STORMWATER DISCH ELIMINATION	02 - Steam Generation Plant	Martin U1	31200	4.53%	-	-
020-WASTEWATER/STORMWATER DISCH ELIMINATION	02 - Steam Generation Plant	Martin U2	31200	4.64%	-	-
020-WASTEWATER/STORMWATER DISCH ELIMINATION Total					**-**	**-**
022-PIPELINE INTEGRITY MANAGEMENT	02 - Steam Generation Plant	Manatee Comm	31100	3.17%	601,217	601,217

022-PIPELINE INTEGRITY MANAGEMENT	02 - Steam Generation Plant	Martin Comm	31100	2.52%	2,271,574	2,271,574
022-PIPELINE INTEGRITY MANAGEMENT Total					**2,872,791**	**2,872,791**
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee Comm	31100	3.17%	1,243,306	1,243,306
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee Comm	31200	7.62%	33,272	33,272
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee Comm	31500	2.34%	26,325	26,325
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee U1	31200	4.64%	45,750	45,750
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee U2	31200	4.99%	37,431	37,431
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Martin Comm	31100	2.52%	37,158	37,158
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Martin Comm	31500	3.57%	-	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Turkey Pt Comm	31100	0.00%	-	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Turkey Pt Comm	31500	0.00%	-	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Turkey Pt U1	31100	0.00%	-	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	StLucie U1	32300	5.11%	712,225	712,225
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	StLucie U1	32400	3.20%	745,335	745,335
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	StLucie U2	32300	3.86%	552,390	552,390
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	Turkey Pt Comm	32100	3.13%	990,124	990,124
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	Turkey Pt Comm	32570	14.29%	245,362	245,362
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtLauderdale Comm	34100	2.20%	189,219	189,219
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtLauderdale Comm	34200	3.09%	1,480,169	1,480,169
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtLauderdale Comm	34300	5.20%	-	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtLauderdale GTs	34100	4.18%	-	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtLauderdale GTs	34200	4.73%	513,250	513,250
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtLauderdale U6 SC Peaker	34100	2.69%		-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtMyers GTs	34100	7.40%	98,715	98,715
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtMyers GTs	34200	7.84%	629,983	629,983
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtMyers GTs	34500	7.77%	12,430	12,430
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtMyers U2	34100	2.34%		361,382
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtMyers U2	34300	3.46%	49,727	49,727
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtMyers U3	34500	3.40%	12,430	12,430
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Martin Comm	34100	2.24%	523,498	982,202
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	PtEverglades Comm	34200	2.90%	2,728,283	2,728,283
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	PtEverglades GTs	34100	0.00%	-	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	PtEverglades GTs	34200	0.00%	-	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	PtEverglades GTs	34500	0.00%	-	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	PtEverglades U5	34200	2.90%	286,434	286,434
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Putnam Comm	34100	0.00%	-	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Putnam Comm	34200	0.00%	-	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Putnam Comm	34500	0.00%	-	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Sanford Comm	34100	2.40%	288,383	288,383
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Martin U8	34200	2.70%	84,868	84,868
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electr	Radial-Retail	35200	1.70%	6,946	6,946
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electr	Transmission Plant - Electri	35200	1.70%	1,142,640	1,145,114
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electr	Transmission Plant - Electri	35300	2.04%	2,903,037	2,903,037
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electr	Transmission Plant - Electri	35800	1.87%	65,655	65,655
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	07 - Distribution Plant - Electric	Mass Distribution Plant	36100	1.75%	3,458,511	3,461,675
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	07 - Distribution Plant - Electric	Mass Distribution Plant	36670	2.00%	70,499	70,499
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	08 - General Plant	General Plant	39000	1.50%	146,691	150,066
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES Total					**19,360,047**	**20,189,146**
024-GAS REBURN	02 - Steam Generation Plant	Manatee U1	31200	4.64%	16,470,024	16,470,024
024-GAS REBURN	02 - Steam Generation Plant	Manatee U2	31200	4.99%	15,393,694	15,393,694
024-GAS REBURN Total					**31,863,719**	**31,863,719**
025-PPE ESP TECHNOLOGY	02 - Steam Generation Plant	PtEverglades U1	31100	0.00%	-	-
025-PPE ESP TECHNOLOGY Total					**-**	**-**
026-UST REPLACEMENT/REMOVAL	08 - General Plant	General Plant	39000	1.50%	115,447	115,447
026-UST REPLACEMENT/REMOVAL Total					**115,447**	**115,447**
027 - Lowest Quality Water Source	05 - Other Generation Plant	Sanford Comm	34300	7.96%		-
027 - Lowest Quality Water Source Total						**-**
028-CWA 316B PHASE II RULE	05 - Other Generation Plant	CapeCanaveral Comm CC	34100	2.69%	771,310	771,310
028-CWA 316B PHASE II RULE Total					**771,310**	**771,310**
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee Comm	31100	3.17%	102,052	102,052
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee U1	31200	4.64%	20,059,060	20,059,060
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee U1	31400	4.03%	7,240,124	7,240,124
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee U2	31200	4.99%	20,457,354	20,457,354
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee U2	31400	3.72%	7,905,907	7,905,907
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin Comm	31200	4.45%	-	-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin Comm	31400	3.48%	-	-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin U1	31200	4.53%	-	-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin U1	31400	3.35%	-	-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin U2	31200	4.64%	-	-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin U2	31400	4.79%	-	-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer Comm U3&4	31200	2.32%	5,419,967	5,725,205
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31100	2.30%	82,366,984	82,366,984
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31200	2.79%	254,475,936	254,626,928
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31400	1.89%	(94,224)	(94,224)
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31500	2.49%	19,615,426	19,615,426
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31600	1.88%	399,586	399,586
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31670	14.29%	-	-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	SJRPP - Comm	31200	1.44%	-	-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	SJRPP - Comm	31500	1.30%	-	-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	SJRPP - Comm	31600	1.31%	-	-
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	FtLauderdale GTs	34300	8.25%	110,242	110,242
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	FtMyers GTs	34300	8.22%	57,855	57,855
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	Martin Comm	34100	2.24%	699,143	699,143
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	Martin Comm	34300	2.56%	244,343	244,343
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	Martin Comm	34500	2.04%	292,499	292,499
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	PtEverglades GTs	34300	0.00%	-	-
031-CLEAN AIR INTERSTATE RULE-CAIR	07 - Distribution Plant - Electric	Mass Distribution Plant	36500	2.57%	1,313	1,313
031-CLEAN AIR INTERSTATE RULE-CAIR Total					**419,353,567**	**419,809,797**
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	Scherer Comm U3&4	31200	2.32%	(1,234,037)	(1,234,037)
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	Scherer U4	31100	2.30%	-	-
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	Scherer U4	31200	2.79%	110,565,526	110,565,526
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	Scherer U4	31500	2.49%	-	-
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	SJRPP - Comm	31200	1.44%	-	-
033-CLEAN AIR MERCURY RULE-CAMR	03 - Nuclear Generation Plant	Scherer U4	31200	2.79%		1,682
033-CLEAN AIR MERCURY RULE-CAMR Total					**109,331,489**	**109,333,171**
034-PSL COOLING WATER SYSTEM INSPECTION & MAINTENANC	03 - Nuclear Generation Plant	StLucie Comm	32100	2.25%		-
034-PSL COOLING WATER SYSTEM INSPECTION & MAINTENANCE Total						**-**
035-MARTIN PLANT DRINKING WATER COMP	02 - Steam Generation Plant	Martin Comm	31100	2.52%	-	-
035-MARTIN PLANT DRINKING WATER COMP Total					**-**	**-**
036-LOW LEV RADI WSTE-LLW	03 - Nuclear Generation Plant	StLucie Comm	32100	2.25%	7,601,405	7,601,405
036-LOW LEV RADI WSTE-LLW	03 - Nuclear Generation Plant	Turkey Pt Comm	32100	3.13%	9,855,399	9,855,399
036-LOW LEV RADI WSTE-LLW Total					**17,456,804**	**17,456,804**
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34000	0.00%	255,507	255,507
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34100	3.49%	5,263,916	5,263,916
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34300	3.36%	115,295,697	115,352,982

037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34500	3.65%	26,746,246	26,805,653
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34630	33.33%	7,279	5,261
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34650	20.00%	24,247	24,247
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34670	14.29%	154,715	154,831
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34800	10.00%		20,100
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electr	Transmission Plant - Electri	35200	1.70%	7,427	7,427
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electr	Transmission Plant - Electri	35300	2.04%	995,394	995,394
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electr	Transmission Plant - Electri	35310	2.64%	1,695,869	1,695,869
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electr	Transmission Plant - Electri	35500	2.32%	394,418	394,418
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electr	Transmission Plant - Electri	35600	2.38%	191,358	191,358
037-DE SOTO SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36100	1.75%	540,994	540,994
037-DE SOTO SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36200	1.90%	1,890,938	1,890,938
037-DE SOTO SOLAR PROJECT	08 - General Plant	General Plant	39220	10.00%	28,426	28,426
037-DE SOTO SOLAR PROJECT	08 - General Plant	General Plant	39720	14.29%	-	-
037-DE SOTO SOLAR PROJECT Total					**153,492,429**	**153,627,320**
038-SPACE COAST SOLAR PROJECT	01 - Intangible Plant	Intangible Plant	30300	various	6,359,027	6,359,027
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast Solar	34100	3.45%	3,893,263	3,893,263
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast Solar	34300	3.30%	51,550,587	51,558,627
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast Solar	34500	3.51%	6,126,699	6,126,699
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast Solar	34630	33.33%	1,105	1,105
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast Solar	34650	20.00%	-	-
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast Solar	34670	14.29%	-	-
038-SPACE COAST SOLAR PROJECT	06 - Transmission Plant - Electr	Transmission Plant - Electri	35300	2.04%	928,529	928,529
038-SPACE COAST SOLAR PROJECT	06 - Transmission Plant - Electr	Transmission Plant - Electri	35310	2.64%	1,328,699	1,328,699
038-SPACE COAST SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36100	1.75%	274,858	274,858
038-SPACE COAST SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36200	1.90%	62,689	62,689
038-SPACE COAST SOLAR PROJECT	08 - General Plant	General Plant	39220	10.00%	31,858	31,858
038-SPACE COAST SOLAR PROJECT	08 - General Plant	General Plant	39720	14.29%	-	-
038-SPACE COAST SOLAR PROJECT Total					**70,557,314**	**70,565,354**
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34000	0.00%	216,844	216,844
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34100	2.99%	20,798,049	20,798,049
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34300	2.88%	399,689,021	400,558,990
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34500	2.99%	4,177,638	4,171,693
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34600	2.85%	56,448	56,448
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34650	20.00%	-	-
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34670	14.29%	150,046	143,061
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin U8	34300	3.37%	423,126	423,126
039-MARTIN SOLAR PROJECT	06 - Transmission Plant - Electr	Transmission Plant - Electri	35500	2.32%	603,692	603,692
039-MARTIN SOLAR PROJECT	06 - Transmission Plant - Electr	Transmission Plant - Electri	35600	2.38%	364,159	364,159
039-MARTIN SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36500	2.57%	-	-
039-MARTIN SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36660	1.42%	94,476	94,476
039-MARTIN SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36760	1.96%	2,728	2,728
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	39220	10.00%	121,101	121,101
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	39240	2.63%	332,682	332,682
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	39290	4.99%	88,938	88,938
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	39420	14.29%	-	-
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	39720	14.29%	-	-
039-MARTIN SOLAR PROJECT Total					**427,118,948**	**427,975,986**
041-PRV MANATEE HEATING SYSTEM	05 - Other Generation Plant	CapeCanaveral Comm	34300	0.00%	4,042,459	4,042,459
041-PRV MANATEE HEATING SYSTEM	05 - Other Generation Plant	Dania Beach EC U7	34300	44 mos.	7,927,943	-
041-PRV MANATEE HEATING SYSTEM	05 - Other Generation Plant	FtLauderdale Comm U4&5	34300	44 mos.		7,930,276
041-PRV MANATEE HEATING SYSTEM	05 - Other Generation Plant	FtMyers U2	34300	3.46%	5,603,547	5,603,547
041-PRV MANATEE HEATING SYSTEM	06 - Transmission Plant - Electr	Transmission Plant - Electri	35300	various	276,404	276,404
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36100	various	73,267	73,267
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36200	various	471,542	471,542
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36410	various	137,247	137,247
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36420	various	36,431	36,431
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36500	various	307,599	307,599
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36660	various	221,326	221,326
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36760	various	168,995	168,841
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36910	various	607	607
041-PRV MANATEE HEATING SYSTEM Total					**19,267,368**	**19,269,547**
042-PTN COOLING CANAL MONITORING SYS	03 - Nuclear Generation Plant	Turkey Pt Comm	32100	3.13%	62,314,631	67,621,510
042-PTN COOLING CANAL MONITORING SYS	03 - Nuclear Generation Plant	Turkey Pt Comm	32500	3.67%	1,037,522	1,037,522
042-PTN COOLING CANAL MONITORING SYS	03 - Nuclear Generation Plant	Turkey Pt Comm	32550	20.00%	544,822	544,822
042-PTN COOLING CANAL MONITORING SYS	05 - Other Generation Plant	Turkey Pt U5	34100	2.33%	-	-
042-PTN COOLING CANAL MONITORING SYS Total					**63,896,975**	**69,203,854**
044-Barley Barber Swamp Iron Mitiga	02 - Steam Generation Plant	Martin Comm	31100	2.52%	164,719	164,719
044-Barley Barber Swamp Iron Mitiga Total					**164,719**	**164,719**
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee Comm	31200	7.62%	153,660	153,660
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U1	31200	4.64%	44,485,716	44,485,716
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U1	31500	4.11%	4,524,074	4,524,074
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U1	31600	3.91%	1,021,918	1,021,918
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U2	31200	4.99%	52,279,530	52,285,732
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U2	31500	4.48%	4,793,798	4,793,798
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U2	31600	4.79%	1,174,454	1,174,454
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U1	31200	4.53%	-	-
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U1	31500	3.12%	-	-
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U1	31600	3.81%	-	-
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U2	31200	4.64%	-	-
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U2	31500	3.56%	-	-
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U2	31600	4.31%	-	-
045-800 MW UNIT ESP PROJECT Total					**108,433,151**	**108,439,353**
047-NPDES Permit Renewal Requirement	03 - Nuclear Generation Plant	StLucie Comm	32100	2.25%		-
047-NPDES Permit Renewal Requirement	03 - Nuclear Generation Plant	StLucie Comm	32300	7.22%	-	2,801,208
047-NPDES Permit Renewal Requirement Total					**-**	**2,801,208**
050-STEAM ELEC EFFLUENT GUIDELI REV	02 - Steam Generation Plant	Scherer U4	31200	2.79%		-
050-STEAM ELEC EFFLUENT GUIDELI REV Total						**-**
054-COAL COMBUSTION RESIDUALS	02 - Steam Generation Plant	Scherer Comm	31100	1.51%	208,650	208,650
054-COAL COMBUSTION RESIDUALS	02 - Steam Generation Plant	Scherer Comm U3&4	31200	2.32%	18,751,871	18,764,434
054-COAL COMBUSTION RESIDUALS	02 - Steam Generation Plant	Scherer U4	31200	2.79%	90,735,857	93,124,003
054-COAL COMBUSTION RESIDUALS	02 - Steam Generation Plant	SJRPP - Comm	31100	1.09%	-	-
054-COAL COMBUSTION RESIDUALS Total					**109,696,378**	**112,097,087**
123-THE PROTECTED SPECIES PROJECT	05 - Other Generation Plant	CapeCanaveral U1CC	34300	2.96%		125,703
123-THE PROTECTED SPECIES PROJECT	05 - Other Generation Plant	FtMyers U2	34100	2.34%		-
123-THE PROTECTED SPECIES PROJECT Total						**125,703**
124 - Turkey Point Clean Water Recovery Center	05 - Other Generation Plant	Turkey Pt U5	34100	2.33%		-
124 - Turkey Point Clean Water Recovery Center Total						**-**
Grand Total					**1,578,244,673**	**1,594,006,231**

FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES
ACT/EST 2021 WACC @10.55%

CAPITAL STRUCTURE AND COST RATES (a)

	Adjusted Retail	Ratio	Midpoint Cost Rates	Weighted Cost	Pre-Tax Weighted Cost
Long term debt	$14,562,650,096	30.989%	3.73%	1.1552%	1.16%
Short term debt	$614,526,761	1.308%	0.75%	0.0098%	0.01%
Preferred stock	$0	0.000%	0.00%	0.0000%	0.00%
Customer Deposits	$386,833,886	0.823%	2.04%	0.0168%	0.02%
Common Equity [b]	$22,399,858,657	47.667%	10.55%	5.0288%	6.66%
Deferred Income Tax	$8,273,619,122	17.606%	0.00%	0.0000%	0.00%
Investment Tax Credits					
Zero cost	$0	0.000%	0.00%	0.0000%	0.00%
Weighted cost	$755,222,884	1.607%	7.86%	0.1264%	0.16%
TOTAL	$46,992,711,405	100.00%		6.34%	8.00%

CALCULATION OF THE WEIGHTED COST FOR CONVERTIBLE INVESTMENT TAX CREDITS (C-ITC) [c]

	Adjusted Retail	Ratio	Cost Rate	Weighted Cost	Pre-Tax Cost
Long term debt	$14,562,650,096	39.40%	3.728%	1.469%	1.469%
Preferred Stock	$0	0.00%	0.000%	0.000%	0.000%
Common Equity	$22,399,858,657	60.60%	10.550%	6.393%	8.471%
TOTAL	$36,962,508,752	100.00%		7.862%	9.939%

RATIO

DEBT COMPONENTS	
Long term debt	1.1552%
Short term debt	0.0098%
Customer Deposits	0.0168%
Tax credits weighted	0.0236%
TOTAL DEBT	**1.2054%**

EQUITY COMPONENTS:	
PREFERRED STOCK	0.0000%
COMMON EQUITY	5.0288%
TAX CREDITS -WEIGHTED	0.1027%
TOTAL EQUITY	**5.1316%**
TOTAL	6.3370%
PRE-TAX EQUITY	6.7988%
PRE-TAX TOTAL	8.0042%

Note:

(a) Forecasted capital structure includes a deferred income tax proration adjustment consistent with FPSC Order No. PSC-2020-0165-PAA-EU, Docket No. 20200118-EU.
(b) Cost rate for common equity represents FPL's mid-point return on equity approved by the FPSC in Order No. PSC-16-0560-AS-EI, Docket Nos. 160021-EI, 160061-EI, 160062-EI, and 160088-EI.

(c) This capital structure applies only to Convertible Investment Tax Credit (C-ITC)

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-1P

January 2022 through December 2022

(1)	(2) Energy	(3) 12 CP Demand	(4) GCP Demand	(5) Total
1. Total Jurisdictional Revenue Requirements for the Projected Period				
a. Projected O&M Activities (a)	$20,270,747	$13,957,195	$7,814,203	$42,042,146
b. Projected Capital Projects (b)	$28,650,278	$292,623,679	$734,889	$322,008,846
c. Total Jurisdictional Revenue Requirements (Line 1a + Line 1b)	$48,921,025	$306,580,875	$8,549,093	$364,050,992
2. Estimated True-Up of Over/(Under) Recovery for the Current Period (c) (f)	$1,182,365	$5,235,624	$147,057	$6,565,046
3. Final True-Up of Over/(Under) Recovery for the Prior Period (d) (f)	$2,021,044	$10,225,281	$260,134	$12,506,459
4. Jurisdictional Amount to be Recovered/(Refunded) (Line 1c - Line 2 - Line 3)	$45,717,617	$291,119,970	$8,141,901	$344,979,487
5. Projected Jurisdictional Amount to be Recovered/(Refunded) Adjusted for Taxes (Line 4 x Revenue Tax Multiplier) (e)	$45,717,617	$291,119,970	$8,141,901	$344,979,487

Notes:

(a) Form 42-2P-1 pg. 2, Columns 6 through 8

(b) Form 42-3P pg. 2, Columns 6 through 8

(c) Includes 2021 Actual/Estimated True-Up amounts for FPL and Gulf - See Forms 42-1E

(d) Includes 2020 Final True-Up amounts for FPL and Gulf - See Forms 42-1A

(e) Pursuant to the proposed Settlement in Docket No. 20210015-EI, the Regulatory Assessment Fee is to be calculated and included as part of the Gross Receipts Tax and Regulatory Assessment Fee and excluded from clause costs

(f) True-Up costs are split proportionally to the split of actual demand-related and energy-related costs from respective True-Up periods.

Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered
O&M Activities

Form 42-2P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
O&M Projects	Strata	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
1 - Air Operating Permit Fees	Base	$14,309	$20,819	$91,624	$16,504	$12,097	$11,898	$11,818	$11,846	$11,963	$12,891	$13,149	$13,029	$241,949
1 - Air Operating Permit Fees	Intermediate	$6,652	$6,652	$25,862	$10,501	$6,652	$7,256	$7,256	$7,256	$7,256	$7,256	$7,256	$7,256	$107,111
3a - Continuous Emission Monitoring Systems	Base	$62,265	$50,541	$55,829	$47,848	$47,641	$49,904	$45,158	$44,761	$50,120	$45,634	$45,798	$69,464	$614,962
3a - Continuous Emission Monitoring Systems	Intermediate	$114,186	$28,009	$54,469	$34,259	$28,009	$33,009	$34,259	$28,009	$33,009	$34,259	$28,554	$43,208	$493,235
3a - Continuous Emission Monitoring Systems	Peaking	$21,688	$5,143	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$26,831
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Base	$7,450	$7,430	$12,532	$8,336	$7,569	$14,045	$7,548	$7,568	$22,563	$7,520	$7,486	$27,451	$137,499
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Distribution	$5,000	$5,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$5,000	$5,000	$100,000
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Intermediate	$0	$0	$10,000	$25	$1,000	$11,176	$0	$0	$10,000	$0	$0	$10,000	$42,201
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Peaking	$0	$0	$0	$4,200	$0	$1	$0	$0	$0	$0	$0	$0	$4,201
8a - Oil Spill Clean-up/Response Equipment	Intermediate	$2,298	$2,298	$2,298	$2,298	$2,298	$2,298	$2,298	$2,298	$2,298	$2,298	$2,298	$2,298	$27,581
8a - Oil Spill Clean-up/Response Equipment	Peaking	$18,596	$18,596	$18,596	$18,596	$18,596	$18,596	$18,596	$18,596	$18,596	$18,596	$18,596	$18,596	$223,157
14 - NPDES Permit Fees	Base	$11,500	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$23,000	$34,500
14 - NPDES Permit Fees	Intermediate	$28,260	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$11,500	$39,760
14 - NPDES Permit Fees	Peaking	$29,440	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$29,440
19 - Oil-filled Equipment and Hazardous Substance Remediation	Base	$0	$0	$0	$25,000	$0	$0	$0	$0	$0	$25,000	$0	$0	$50,000
19 - Oil-filled Equipment and Hazardous Substance Remediation	Distribution	$444,952	$544,432	$533,277	$546,202	$546,202	$544,532	$544,532	$545,527	$551,015	$564,532	$564,532	$564,532	$6,494,265
19 - Oil-filled Equipment and Hazardous Substance Remediation	Transmission	$100,542	$144,587	$145,500	$145,252	$144,502	$101,625	$100,077	$99,502	$95,252	$144,502	$155,252	$156,427	$1,533,024
21 - St. Lucie Turtle Nets	Base	$30,700	$30,700	$30,700	$30,700	$30,700	$30,700	$30,700	$30,700	$30,700	$30,700	$30,700	$30,700	$368,400
23 - SPCC - Spill Prevention, Control & Countermeasures	Base	$0	$7,500	$0	$0	$7,500	$0	$0	$7,500	$0	$0	$7,500	$0	$30,000
23 - SPCC - Spill Prevention, Control & Countermeasures	Distribution	$49,792	$51,092	$51,092	$49,007	$49,327	$49,222	$49,327	$50,112	$50,682	$49,007	$50,197	$51,085	$599,938
23 - SPCC - Spill Prevention, Control & Countermeasures	Intermediate	$1,544	$1,544	$4,544	$1,544	$1,544	$4,544	$1,544	$1,544	$4,544	$1,544	$1,544	$4,544	$30,528
23 - SPCC - Spill Prevention, Control & Countermeasures	Peaking	$456	$456	$456	$456	$456	$456	$456	$456	$456	$456	$456	$456	$5,472
23 - SPCC - Spill Prevention, Control & Countermeasures	Transmission	$16,130	$16,004	$16,405	$16,158	$16,295	$16,286	$16,163	$16,419	$16,292	$16,153	$16,264	$16,251	$194,818
27 - Lowest Quality Water Source	Base	$0	$0	$16,500	$0	$11,500	$5,000	$11,500	$0	$16,500	$14,500	$31,000	$5,000	$111,500
27 - Lowest Quality Water Source	Intermediate	$8,500	$8,500	$8,500	$8,500	$8,500	$8,500	$8,500	$8,500	$8,500	$8,500	$8,500	$8,500	$102,000
28 - CWA 316(b) Phase II Rule	Base	$1,010	$3,461	$3,618	$1,021	$1,075	$1,071	$1,023	$1,124	$1,074	$6,019	$6,063	$6,058	$32,617
28 - CWA 316(b) Phase II Rule	Intermediate	$6,377	$6,286	$10,577	$6,398	$14,747	$18,741	$11,651	$15,838	$11,745	$15,144	$11,725	$11,715	$140,944
28 - CWA 316(b) Phase II Rule	Peaking	$5,645	$5,370	$6,247	$5,708	$6,006	$5,987	$5,717	$6,278	$6,001	$5,695	$5,938	$5,910	$70,502
37 - DeSoto Next Generation Solar Energy Center	Solar	$46,157	$32,677	$45,223	$94,236	$33,396	$35,201	$37,865	$34,939	$34,685	$38,464	$38,236	$34,014	$505,094
38 - Space Coast Next Generation Solar Energy Center	Solar	$25,794	$23,058	$21,171	$19,905	$24,558	$30,244	$19,808	$28,708	$20,672	$19,516	$23,974	$26,091	$283,499
39 - Martin Next Generation Solar Energy Center	Intermediate	$353,872	$348,002	$362,328	$351,577	$357,665	$357,187	$351,808	$363,085	$357,532	$352,135	$359,149	$358,432	$4,272,772
41 - Manatee Temporary Heating System	Intermediate	$26,200	$26,200	$27,200	$15,200	$15,000	$15,000	$15,000	$260,000	$258,000	$283,000	$253,000	$8,000	$1,201,800
42 - Turkey Point Cooling Canal Monitoring Plan	Base	$661,361	$706,500	$937,654	$660,418	$690,446	$1,059,600	$660,418	$792,446	$911,600	$660,418	$690,446	$1,557,943	$9,989,250
47 - NPDES Permit Renewal Requirements	Base	$18,000	$0	$2,585	$18,000	$7,000	$0	$18,000	$0	$0	$27,585	$0	$0	$91,170
47 - NPDES Permit Renewal Requirements	Intermediate	$8,978	$6,750	$16,353	$0	$0	$11,500	$8,640	$0	$7,840	$6,750	$5,153	$0	$71,964
47 - NPDES Permit Renewal Requirements	Peaking	$0	$0	$3,360	$0	$0	$0	$3,360	$0	$3,360	$0	$3,360	$0	$13,440
48 - Industrial Boiler MACT	Intermediate	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,000	$0	$0	$13,000
50 - Steam Electric Effluent Guidelines Revised Rules	Base	$1,255,399	$75,565	$75,565	$75,565	$75,565	$75,565	$75,565	$75,565	$75,565	$75,565	$75,565	$75,565	$2,086,610
51 - Gopher Tortoise Relocations	Intermediate	$2,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000
51 - Gopher Tortoise Relocations	Peaking	$0	$0	$0	$0	$0	$0	$0	$13,659	$13,659	$0	$0	$7,000	$34,318
54 - Coal Combustion Residuals	Base	$196,267	$202,742	$220,247	$198,362	$193,985	$211,218	$154,326	$153,733	$171,268	$154,627	$154,922	$173,127	$2,184,824
54 - Coal Combustion Residuals	Intermediate	$14,618	$14,604	$26,174	$26,677	$14,700	$14,683	$14,685	$26,199	$26,195	$14,666	$14,642	$14,618	$222,460
426 - Air Quality Compliance Program	Base	$533,213	$699,287	$878,212	$670,696	$555,023	$664,086	$543,768	$558,820	$617,350	$562,550	$607,657	$606,462	$7,497,124
426 - Air Quality Compliance Program	Intermediate	$28,153	$116,672	$41,653	$41,653	$28,153	$28,153	$28,153	$28,153	$70,153	$94,039	$28,153	$28,153	$561,237
427 - General Water Quality	Base	$94,597	$97,147	$139,622	$100,904	$93,413	$143,978	$103,310	$109,725	$148,365	$109,276	$113,261	$161,744	$1,415,342
427 - General Water Quality	Intermediate	$8,887	$9,000	$23,300	$7,750	$7,300	$15,123	$17,625	$7,300	$13,300	$7,750	$7,300	$13,300	$137,935
427 - General Water Quality	Transmission	$0	$0	$20,000	$20,000	$20,000	$0	$0	$0	$0	$20,000	$20,000	$0	$100,000
428 - Asbestos Fees	Base	$500	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$500
428 - Asbestos Fees	Intermediate	$1,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,000
429 - Env Auditing/Assessment	Base	$0	$0	$2,601	$0	$0	$0	$0	$0	$0	$2,601	$0	$0	$5,202
430 - General Solid & Hazardous Waste	Base	$20,200	$20,159	$24,216	$24,376	$20,443	$34,145	$20,400	$20,441	$21,680	$26,844	$20,273	$26,460	$279,637
430 - General Solid & Hazardous Waste	Distribution	$55,000	$55,000	$45,000	$55,000	$55,000	$45,000	$55,000	$55,000	$45,000	$55,000	$55,000	$45,000	$620,000
430 - General Solid & Hazardous Waste	Intermediate	$0	$0	$0	$0	$0	$7,500	$0	$0	$0	$0	$0	$0	$7,500
431 - Title V	Base	$12,175	$18,893	$14,809	$12,316	$12,370	$14,831	$18,585	$12,368	$14,859	$18,540	$12,234	$21,127	$183,107
NA-Amortization of Gains on Sales of Emissions Allowances	Base	$0	$0	($15)	$0	$0	($15)	$0	$0	($15)	$0	$0	($15)	($59)
	Total	$4,349,663	$3,416,674	$4,035,884	$3,381,148	$3,176,232	$3,707,847	$3,064,439	$3,453,973	$3,769,633	$3,562,532	$3,500,134	$4,249,001	$43,667,161

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered
O&M Activities

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
		Monthly Data	Jurisdictionalization		Method of Classification		
O&M Projects	Strata	Twelve Month Total	Jurisdictional Factor	Juris Twelve Month Amount	Energy	CP Demand	GCP Demand
1 - Air Operating Permit Fees	Base	$241,949	95.891700%	$232,009	$232,009	$0	$0
1 - Air Operating Permit Fees	Intermediate	$107,111	94.755800%	$101,493	$101,493	$0	$0
3a - Continuous Emission Monitoring Systems	Base	$614,962	95.891700%	$589,698	$589,698	$0	$0
3a - Continuous Emission Monitoring Systems	Intermediate	$493,235	94.755800%	$467,369	$467,369	$0	$0
3a - Continuous Emission Monitoring Systems	Peaking	$26,831	95.772100%	$25,697	$25,697	$0	$0
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Base	$137,499	95.931400%	$131,904	$0	$131,904	$0
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Distribution	$100,000	100.000000%	$100,000	$0	$0	$100,000
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Intermediate	$42,201	95.428700%	$40,272	$0	$40,272	$0
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Peaking	$4,201	95.183700%	$3,999	$0	$3,999	$0
8a - Oil Spill Clean-up/Response Equipment	Intermediate	$27,581	94.755800%	$26,135	$26,135	$0	$0
8a - Oil Spill Clean-up/Response Equipment	Peaking	$223,157	95.772100%	$213,722	$213,722	$0	$0
14 - NPDES Permit Fees	Base	$34,500	95.931400%	$33,096	$0	$33,096	$0
14 - NPDES Permit Fees	Intermediate	$39,760	95.428700%	$37,942	$0	$37,942	$0
14 - NPDES Permit Fees	Peaking	$29,440	95.183700%	$28,022	$0	$28,022	$0
19 - Oil-filled Equipment and Hazardous Substance Remediation	Base	$50,000	95.931400%	$47,966	$0	$47,966	$0
19 - Oil-filled Equipment and Hazardous Substance Remediation	Distribution	$6,494,265	100.000000%	$6,494,265	$0	$0	$6,494,265
19 - Oil-filled Equipment and Hazardous Substance Remediation	Transmission	$1,533,024	90.258100%	$1,383,678	$0	$1,383,678	$0
21 - St. Lucie Turtle Nets	Base	$368,400	95.931400%	$353,411	$0	$353,411	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Base	$30,000	95.931400%	$28,779	$0	$28,779	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Distribution	$599,938	100.000000%	$599,938	$0	$0	$599,938
23 - SPCC - Spill Prevention, Control & Countermeasures	Intermediate	$30,528	95.428700%	$29,132	$0	$29,132	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Peaking	$5,472	95.183700%	$5,208	$0	$5,208	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Transmission	$194,818	90.258100%	$175,839	$0	$175,839	$0
27 - Lowest Quality Water Source	Base	$111,500	95.931400%	$106,964	$0	$106,964	$0
27 - Lowest Quality Water Source	Intermediate	$102,000	95.428700%	$97,337	$0	$97,337	$0
28 - CWA 316(b) Phase II Rule	Base	$32,617	95.931400%	$31,290	$0	$31,290	$0
28 - CWA 316(b) Phase II Rule	Intermediate	$140,944	95.428700%	$134,501	$0	$134,501	$0
28 - CWA 316(b) Phase II Rule	Peaking	$70,502	95.183700%	$67,107	$0	$67,107	$0
37 - DeSoto Next Generation Solar Energy Center	Solar	$505,094	95.931400%	$484,543	$0	$484,543	$0
38 - Space Coast Next Generation Solar Energy Center	Solar	$283,499	95.931400%	$271,964	$0	$271,964	$0
39 - Martin Next Generation Solar Energy Center	Intermediate	$4,272,772	95.428700%	$4,077,450	$0	$4,077,450	$0
41 - Manatee Temporary Heating System	Intermediate	$1,201,800	94.755800%	$1,138,775	$1,138,775	$0	$0
42 - Turkey Point Cooling Canal Monitoring Plan	Base	$9,989,250	95.891700%	$9,578,862	$9,578,862	$0	$0
47 - NPDES Permit Renewal Requirements	Base	$91,170	95.931400%	$87,461	$0	$87,461	$0
47 - NPDES Permit Renewal Requirements	Intermediate	$71,964	95.428700%	$68,674	$0	$68,674	$0
47 - NPDES Permit Renewal Requirements	Peaking	$13,440	95.183700%	$12,793	$0	$12,793	$0
48 - Industrial Boiler MACT	Intermediate	$13,000	95.428700%	$12,406	$0	$12,406	$0
50 - Steam Electric Effluent Guidelines Revised Rules	Base	$2,086,610	95.931400%	$2,001,714	$0	$2,001,714	$0
51 - Gopher Tortoise Relocations	Intermediate	$2,000	95.428700%	$1,909	$0	$1,909	$0
51 - Gopher Tortoise Relocations	Peaking	$34,318	95.183700%	$32,665	$0	$32,665	$0
54 - Coal Combustion Residuals	Base	$2,184,824	95.931400%	$2,095,933	$0	$2,095,933	$0
54 - Coal Combustion Residuals	Intermediate	$222,460	95.428700%	$212,291	$0	$212,291	$0
426 - Air Quality Compliance Program	Base	$7,497,124	95.891700%	$7,189,119	$7,189,119	$0	$0
426 - Air Quality Compliance Program	Intermediate	$561,237	94.755800%	$531,805	$531,805	$0	$0
427 - General Water Quality	Base	$1,415,342	95.931400%	$1,357,758	$0	$1,357,758	$0
427 - General Water Quality	Intermediate	$137,935	95.428700%	$131,630	$0	$131,630	$0
427 - General Water Quality	Transmission	$100,000	90.258100%	$90,258	$0	$90,258	$0
428 - Asbestos Fees	Base	$500	95.891700%	$479	$479	$0	$0
428 - Asbestos Fees	Intermediate	$1,000	94.755800%	$948	$0	$948	$0
429 - Env Auditing/Assessment	Base	$5,202	95.931400%	$4,990	$0	$4,990	$0
430 - General Solid & Hazardous Waste	Base	$279,637	95.931400%	$268,259	$0	$268,259	$0
430 - General Solid & Hazardous Waste	Distribution	$620,000	100.000000%	$620,000	$0	$0	$620,000
430 - General Solid & Hazardous Waste	Intermediate	$7,500	95.428700%	$7,157	$0	$7,157	$0
431 - Title V	Base	$183,107	95.891700%	$175,585	$175,585	$0	$0
NA-Amortization of Gains on Sales of Emissions Allowances	Base	($59)	95.891700%	($56)	$0	($56)	$0
	Total	$43,667,161		$42,042,146	$20,270,747	$13,957,195	$7,814,203

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered
O&M Activities

Form 42-2P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
1. Total of O&M Activities	$4,349,663	$3,416,674	$4,035,884	$3,381,148	$3,176,232	$3,707,847	$3,064,439	$3,453,973	$3,769,633	$3,562,532	$3,500,134	$4,249,001	$43,667,161
2. Recoverable Costs Jurisdictionalized on Energy													
Production - Base	$1,283,823	$1,496,040	$1,978,114	$1,407,782	$1,317,577	$1,800,305	$1,279,747	$1,420,241	$1,605,877	$1,300,034	$1,369,284	$2,268,010	$18,526,833
Production - Intermediate	$178,489	$179,831	$151,481	$103,911	$80,111	$85,716	$86,966	$325,716	$370,716	$420,852	$319,261	$88,915	$2,391,964
Production - Peaking	$40,285	$23,739	$18,596	$18,596	$18,596	$18,596	$18,596	$18,596	$18,596	$18,596	$18,596	$18,596	$249,988
Production - Solar													
3. Recoverable Costs Jurisdictionalized on CP Demand													
Production - Base	$1,635,123	$444,703	$528,186	$482,264	$448,750	$515,722	$422,372	$406,355	$487,714	$480,237	$446,770	$529,104	$6,827,301
Production - Intermediate	$433,036	$394,686	$461,776	$402,471	$405,455	$448,954	$414,453	$422,465	$439,656	$419,489	$408,014	$432,609	$5,083,064
Production - Peaking	$35,541	$5,826	$10,063	$10,364	$6,462	$6,444	$9,533	$20,393	$23,476	$6,151	$9,754	$13,366	$157,373
Production - Solar	$71,951	$55,735	$66,394	$114,141	$57,954	$65,445	$57,674	$63,647	$55,356	$57,979	$62,210	$60,105	$788,592
Transmission	$116,672	$160,591	$181,905	$181,411	$180,797	$117,911	$116,240	$115,921	$111,545	$180,655	$191,516	$172,678	$1,827,842
Distribution	$554,744	$655,524	$639,369	$660,209	$660,529	$648,754	$658,859	$660,639	$656,697	$678,539	$674,729	$665,617	$7,814,203
4. Retail Energy Jurisdictional Factors													
Production - Base	95.891700%	95.891700%	95.891700%	95.891700%	95.891700%	95.891700%	95.891700%	95.891700%	95.891700%	95.891700%	95.891700%	95.891700%	
Production - Intermediate	94.755800%	94.755800%	94.755800%	94.755800%	94.755800%	94.755800%	94.755800%	94.755800%	94.755800%	94.755800%	94.755800%	94.755800%	
Production - Peaking	95.772100%	95.772100%	95.772100%	95.772100%	95.772100%	95.772100%	95.772100%	95.772100%	95.772100%	95.772100%	95.772100%	95.772100%	
Production - Solar	95.891700%	95.891700%	95.891700%	95.891700%	95.891700%	95.891700%	95.891700%	95.891700%	95.891700%	95.891700%	95.891700%	95.891700%	
5. Retail Demand Jurisdictional Factors													
Production - Base	95.931400%	95.931400%	95.931400%	95.931400%	95.931400%	95.931400%	95.931400%	95.931400%	95.931400%	95.931400%	95.931400%	95.931400%	
Production - Intermediate	95.428700%	95.428700%	95.428700%	95.428700%	95.428700%	95.428700%	95.428700%	95.428700%	95.428700%	95.428700%	95.428700%	95.428700%	
Production - Peaking	95.183700%	95.183700%	95.183700%	95.183700%	95.183700%	95.183700%	95.183700%	95.183700%	95.183700%	95.183700%	95.183700%	95.183700%	
Production - Solar	95.931400%	95.931400%	95.931400%	95.931400%	95.931400%	95.931400%	95.931400%	95.931400%	95.931400%	95.931400%	95.931400%	95.931400%	
Transmission	90.258100%	90.258100%	90.258100%	90.258100%	90.258100%	90.258100%	90.258100%	90.258100%	90.258100%	90.258100%	90.258100%	90.258100%	
Distribution	100.000000%	100.000000%	100.000000%	100.000000%	100.000000%	100.000000%	100.000000%	100.000000%	100.000000%	100.000000%	100.000000%	100.000000%	
6. Jurisdictional Recoverable Costs													
Production - Base	$2,799,676	$1,861,188	$2,403,544	$1,812,589	$1,693,939	$2,221,082	$1,632,358	$1,751,715	$2,007,773	$1,707,322	$1,741,622	$2,682,410	$24,315,220
Production - Intermediate	$582,369	$547,043	$584,204	$482,534	$462,831	$509,652	$477,912	$711,788	$770,833	$799,095	$691,880	$497,086	$7,117,227
Production - Peaking	$72,411	$28,280	$27,389	$27,675	$23,961	$23,944	$26,884	$37,221	$40,155	$23,665	$27,095	$30,532	$389,212
Production - Solar	$69,024	$53,468	$63,692	$109,497	$55,596	$62,783	$55,327	$61,058	$53,104	$55,620	$59,679	$57,660	$756,508
Transmission	$105,306	$144,947	$164,184	$163,738	$163,184	$106,424	$104,916	$104,628	$100,678	$163,056	$172,859	$155,856	$1,649,776
Distribution	$554,744	$655,524	$639,369	$660,209	$660,529	$648,754	$658,859	$660,639	$656,697	$678,539	$674,729	$665,617	$7,814,203
7. Total Jurisdictional Recoverable Costs for O&M Activities	$4,183,529	$3,290,450	$3,882,381	$3,256,241	$3,060,040	$3,572,638	$2,956,256	$3,327,048	$3,629,240	$3,427,297	$3,367,864	$4,089,161	$42,042,146

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered
Capital Projects

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Capital Projects	Strata	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
2 - Low NOX Burner Technology	Base	$141,057	$140,850	$140,643	$140,436	$140,229	$140,022	$139,815	$139,608	$139,401	$139,194	$138,988	$138,781	$1,679,025
2 - Low NOX Burner Technology	Peaking	$4,400	$4,379	$4,358	$4,337	$4,315	$4,294	$4,273	$4,251	$4,230	$4,209	$4,187	$4,166	$51,398
3 - Continuous Emission Monitoring Systems	Base	$48,676	$48,304	$48,195	$48,085	$47,976	$47,867	$47,757	$47,648	$47,538	$47,429	$47,319	$47,210	$574,004
3 - Continuous Emission Monitoring Systems	Intermediate	$22,547	$22,448	$23,494	$25,734	$29,160	$31,384	$31,292	$31,199	$31,107	$33,400	$35,693	$36,782	$354,239
3 - Continuous Emission Monitoring Systems	Peaking	$13,108	$12,768	$12,728	$12,688	$12,648	$12,608	$12,568	$12,528	$12,488	$12,448	$12,408	$12,368	$151,356
5 - Maintenance of Stationary Above Ground Fuel Tanks	Base	$340	$339	$338	$337	$335	$334	$333	$332	$330	$329	$328	$326	$4,001
5 - Maintenance of Stationary Above Ground Fuel Tanks	General	$61,774	$61,704	$61,634	$61,564	$61,494	$61,424	$61,354	$61,284	$61,214	$61,144	$61,074	$61,004	$736,673
5 - Maintenance of Stationary Above Ground Fuel Tanks	Intermediate	$17,051	$16,552	$16,499	$16,446	$16,393	$16,340	$16,287	$16,234	$16,181	$16,128	$16,075	$16,022	$196,207
5 - Maintenance of Stationary Above Ground Fuel Tanks	Peaking	$56,377	$55,218	$54,986	$54,755	$54,523	$54,292	$54,060	$53,829	$53,597	$53,366	$53,135	$52,903	$651,041
7 - Relocate Turbine Lube Oil Underground Piping to Above Ground	Base	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8 - Oil Spill Cleanup/Response Equipment	Distribution	$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$261
8 - Oil Spill Cleanup/Response Equipment	General	$27	$27	$27	$27	$27	$27	$27	$27	$27	$27	$27	$27	$326
8 - Oil Spill Cleanup/Response Equipment	Intermediate	$12,063	$11,553	$11,015	$11,032	$11,048	$10,955	$10,840	$10,836	$10,854	$10,809	$10,763	$10,670	$132,439
8 - Oil Spill Cleanup/Response Equipment	Peaking	$5,458	$5,276	$4,873	$4,889	$4,905	$4,838	$4,755	$4,755	$4,772	$4,741	$4,710	$4,643	$58,614
10 - Relocate Storm Water Runoff	Base	$497	$496	$494	$493	$491	$490	$488	$487	$485	$484	$482	$481	$5,868
12 - Scherer Discharge Pipeline	Base	$2,055	$2,281	$2,275	$2,269	$2,263	$2,257	$2,251	$2,246	$2,240	$2,234	$2,228	$2,222	$26,821
19 - Oil-filled Equipment and Hazardous Substance Remediation	Distribution	$37,418	$37,402	$37,387	$37,372	$37,559	$37,949	$38,340	$38,730	$38,951	$38,984	$38,982	$38,967	$458,041
19 - Oil-filled Equipment and Hazardous Substance Remediation	Transmission	$6,869	$6,858	$6,847	$6,836	$6,825	$6,814	$6,803	$6,792	$6,781	$6,770	$6,759	$6,748	$81,700
20 - Wastewater Discharge Elimination & Reuse	Peaking	$5,828	$5,812	$5,797	$5,782	$5,767	$5,752	$5,737	$5,722	$5,707	$5,692	$5,677	$5,662	$68,935
21 - St. Lucie Turtle Nets	Base	$60,766	$60,678	$60,590	$60,501	$60,413	$60,325	$60,237	$60,149	$60,061	$59,972	$59,884	$59,796	$723,372
22 - Pipeline Integrity Management	Intermediate	$11,267	$11,730	$11,706	$11,681	$11,657	$11,633	$11,609	$11,585	$11,561	$11,537	$11,513	$11,488	$138,966
22 - Pipeline Integrity Management	Peaking	$9,469	$10,094	$10,072	$10,051	$10,029	$10,008	$9,987	$9,965	$9,944	$9,922	$9,901	$9,879	$119,321
23 - SPCC - Spill Prevention, Control & Countermeasures	Base	$34,882	$36,526	$38,319	$39,231	$39,111	$38,992	$38,872	$38,752	$38,632	$38,513	$38,393	$38,273	$458,496
23 - SPCC - Spill Prevention, Control & Countermeasures	Distribution	$21,684	$21,649	$21,614	$21,578	$21,543	$21,508	$21,473	$21,438	$21,403	$21,367	$21,332	$21,297	$257,887
23 - SPCC - Spill Prevention, Control & Countermeasures	General	$1,334	$1,676	$1,909	$1,958	$1,954	$1,951	$1,948	$1,945	$1,941	$1,938	$1,935	$1,932	$22,421
23 - SPCC - Spill Prevention, Control & Countermeasures	Intermediate	$63,748	$64,405	$64,227	$64,050	$63,872	$63,695	$63,517	$63,340	$63,162	$62,984	$62,807	$62,629	$762,437
23 - SPCC - Spill Prevention, Control & Countermeasures	Peaking	$40,375	$41,349	$41,175	$41,348	$41,867	$42,386	$42,905	$43,424	$44,737	$45,699	$45,515	$45,330	$516,109
23 - SPCC - Spill Prevention, Control & Countermeasures	Transmission	$30,579	$30,533	$30,488	$30,442	$30,397	$30,352	$30,306	$30,261	$30,215	$30,170	$30,125	$30,079	$363,946
24 - Manatee Reburn	Peaking	$171,474	$172,927	$172,479	$172,032	$171,584	$171,137	$170,689	$170,242	$169,794	$169,347	$168,899	$168,452	$2,049,056
26 - UST Remove/Replacement	General	$546	$545	$544	$543	$542	$541	$540	$539	$538	$537	$536	$535	$6,487
27 - Lowest Quality Water Source	Base	$136,253	$135,905	$135,558	$135,211	$134,863	$134,516	$134,169	$133,821	$133,824	$134,176	$134,529	$134,881	$1,617,707
27 - Lowest Quality Water Source	Intermediate	$221,126	$233,767	$247,274	$260,780	$273,421	$286,928	$300,434	$313,075	$327,101	$341,128	$367,035	$403,127	$3,575,197
28 - CWA 316(b) Phase II Rule	Intermediate	$47,940	$47,824	$47,708	$47,592	$47,476	$47,360	$47,244	$47,128	$47,012	$46,896	$46,780	$46,664	$567,623
34 - St Lucie Cooling Water System Inspection & Maintenance	Base	$30,293	$30,293	$30,293	$30,293	$30,323	$30,447	$30,657	$31,133	$33,125	$36,990	$41,572	$48,972	$404,389
35 - Martin Plant Drinking Water System Compliance	Intermediate	$1,106	$1,103	$1,100	$1,097	$1,094	$1,091	$1,089	$1,086	$1,083	$1,080	$1,077	$1,074	$13,080
35 - Martin Plant Drinking Water System Compliance	Peaking	$834	$832	$830	$828	$826	$823	$821	$819	$817	$815	$813	$810	$9,868
36 - Low-Level Radioactive Waste Storage	Base	$135,095	$134,823	$134,551	$134,279	$134,007	$133,735	$133,463	$133,191	$132,919	$132,647	$132,375	$132,103	$1,603,192
37 - DeSoto Next Generation Solar Energy Center	Solar	$939,280	$936,061	$932,769	$929,501	$926,341	$923,180	$920,024	$916,867	$913,672	$910,477	$907,282	$904,086	$11,059,540
38 - Space Coast Next Generation Solar Energy Center	Solar	$437,344	$435,925	$434,505	$433,085	$431,665	$430,245	$428,826	$427,406	$425,986	$424,566	$423,146	$421,727	$5,154,426
39 - Martin Next Generation Solar Energy Center	Intermediate	$2,730,698	$2,725,129	$2,718,709	$2,712,290	$2,705,855	$2,699,421	$2,692,987	$2,686,514	$2,679,976	$2,673,417	$2,666,861	$2,660,261	$32,352,118
41 - Manatee Temporary Heating System	Distribution	$1,550	$1,550	$1,550	$1,550	$1,550	$1,550	$1,550	$1,550	$1,550	$1,550	$1,550	$1,550	$18,601
41 - Manatee Temporary Heating System	Intermediate	$254,039	$252,702	$251,365	$250,028	$248,691	$247,354	$246,017	$244,680	$243,343	$242,006	$240,669	$239,332	$2,960,225
41 - Manatee Temporary Heating System	Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
42 - Turkey Point Cooling Canal Monitoring Plan	Base	$620,794	$620,146	$619,572	$619,070	$618,606	$618,688	$619,087	$622,074	$624,818	$624,032	$622,736	$638,269	$7,467,893
44 - Martin Plant Barley Barber Swamp Iron Mitigation	Intermediate	$681	$680	$678	$677	$676	$674	$673	$672	$670	$669	$668	$666	$8,083
44 - Martin Plant Barley Barber Swamp Iron Mitigation	Peaking	$514	$513	$512	$511	$510	$509	$508	$507	$506	$505	$504	$503	$6,098
47 - NPDES Permit Renewal Requirements	Base	$136,005	$138,490	$140,955	$140,564	$140,173	$139,782	$139,391	$139,000	$138,609	$138,218	$137,827	$137,436	$1,666,452
47 - NPDES Permit Renewal Requirements	Intermediate	$36,727	$36,626	$36,525	$36,423	$36,322	$36,221	$36,120	$36,018	$35,917	$35,816	$35,714	$35,613	$434,043
50 - Steam Electric Effluent Guidelines Revised Rules	Base	$66,399	$62,419	$62,454	$62,489	$62,524	$62,560	$62,595	$62,630	$62,665	$62,700	$62,736	$62,771	$754,942
54 - Coal Combustion Residuals	Base	$2,551,372	$2,869,122	$2,875,140	$2,878,908	$2,881,602	$2,883,425	$2,882,575	$2,879,627	$2,894,557	$2,909,812	$2,907,458	$2,913,106	$34,326,705
54 - Coal Combustion Residuals	Intermediate	$757,759	$764,395	$776,549	$792,214	$805,190	$817,151	$852,373	$891,975	$909,017	$1,086,390	$1,258,438	$1,260,931	$10,972,382
123 - The Protected Species Project	Intermediate	$2,520	$2,518	$8,268	$14,017	$14,015	$16,478	$18,941	$18,939	$18,937	$21,478	$24,520	$25,003	$185,636
124 - FPL Miami-Dade Clean Water Recovery Center	Intermediate	$20,627	$25,831	$37,087	$49,970	$58,463	$66,938	$75,311	$83,770	$102,609	$132,767	$167,264	$205,079	$1,025,717
401 - Air Quality Assurance Testing	Base	$1,377	$1,370	$1,363	$1,357	$1,350	$1,343	$1,336	$1,329	$1,323	$1,316	$1,309	$1,302	$16,076
402 - Crist 5, 6 & 7 Precipitator Projects	Base	$254,815	$254,621	$254,427	$254,233	$254,040	$253,846	$253,652	$253,458	$253,265	$253,071	$252,877	$252,683	$3,044,987
403 - Crist 7 Flue Gas Conditioning	Base	$10,207	$10,207	$10,207	$10,207	$10,207	$10,207	$10,207	$10,207	$10,207	$10,207	$10,207	$10,207	$122,480
408 - Crist Cooling Tower Cell	Base	$3,621	$3,621	$3,621	$3,621	$3,621	$3,621	$3,621	$3,621	$3,621	$3,621	$3,621	$3,621	$43,453
410 - Crist Diesel Fuel Oil Remediation	Base	$90	$90	$89	$89	$88	$88	$87	$87	$86	$86	$85	$85	$1,050
413 - Sodium Injection System	Base	$917	$917	$917	$917	$917	$917	$917	$917	$917	$917	$917	$917	$11,007
414 - Smith Stormwater Collection System	Intermediate	$12,953	$12,880	$12,806	$12,732	$12,658	$12,585	$12,511	$12,437	$12,364	$12,290	$12,216	$12,142	$150,575

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered
Capital Projects

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Capital Projects	Strata	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
415 - Smith Waste Water Treatment Facility	Intermediate	$7,564	$7,547	$7,529	$7,512	$7,495	$7,478	$7,461	$7,444	$7,426	$7,409	$7,392	$7,375	$89,631
416 - Daniel Ash Management Project	Base	$86,310	$86,056	$85,801	$85,547	$85,293	$85,039	$84,784	$84,530	$84,276	$84,021	$83,767	$83,513	$1,018,936
419 - Crist FDEP Agreement for Ozone Attainment	Base	$660,446	$659,487	$658,527	$657,568	$656,608	$655,649	$654,689	$653,730	$652,770	$651,811	$650,852	$649,892	$7,862,030
422 - Precipitator Upgrades for CAM Compliance	Base	$51,960	$51,960	$51,960	$51,960	$51,960	$51,960	$51,960	$51,960	$51,960	$51,960	$51,960	$51,960	$623,520
426 - Air Quality Compliance Program	Base	$12,577,292	$13,494,575	$13,469,843	$13,445,456	$13,420,202	$13,394,422	$13,368,116	$13,341,983	$13,316,373	$13,291,111	$13,265,847	$13,240,582	$159,625,802
426 - Air Quality Compliance Program	Distribution	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8	$99
426 - Air Quality Compliance Program	General	$65	$65	$65	$65	$65	$64	$64	$64	$64	$64	$63	$63	$771
426 - Air Quality Compliance Program	Intermediate	$10,251	$10,249	$10,228	$10,207	$10,186	$10,164	$10,143	$10,122	$10,101	$10,079	$10,058	$10,037	$121,825
426 - Air Quality Compliance Program	Peaking	$2,489,505	$2,602,470	$2,595,716	$2,588,963	$2,582,209	$2,575,456	$2,568,703	$2,561,949	$2,555,196	$2,548,443	$2,541,689	$2,534,936	$30,745,235
426 - Air Quality Compliance Program	Transmission	$42,633	$42,536	$42,439	$42,342	$42,245	$42,148	$42,051	$41,954	$41,857	$41,760	$41,662	$41,565	$505,192
427 - General Water Quality	Base	$155,422	$159,286	$163,141	$166,987	$175,887	$181,603	$192,642	$202,632	$202,127	$201,621	$201,116	$200,610	$2,203,075
NA-Amortization of Gains on Sales of Emissions Allowances	Base	$42,822	$42,822	$42,823	$42,823	$42,823	$42,823	$42,823	$42,823	$42,823	$42,823	$42,823	$42,823	$513,872
Smith Units 1 & 2 Reg Asset	Base	$229,573	$228,766	$227,958	$227,151	$226,344	$225,537	$224,730	$223,922	$223,115	$222,308	$221,501	$220,693	$2,701,598
	Total	$26,648,479	$28,010,585	$28,018,158	$28,027,641	$28,027,353	$28,024,231	$28,044,445	$28,065,827	$28,086,505	$28,282,455	$28,471,219	$28,527,677	$336,234,576

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered
Capital Projects

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
		Monthly Data	Jurisdictionalization		Method of Classification		
Capital Projects	Strata	Twelve Month Total	Jurisdictional Factor	Juris Twelve Month Amount	Energy	CP Demand	GCP Demand
2 - Low NOX Burner Technology	Base	$1,679,025	95.931400%	$1,610,712	$1,610,712	$0	$0
2 - Low NOX Burner Technology	Peaking	$51,398	95.183700%	$48,923	$48,923	$0	$0
3 - Continuous Emission Monitoring Systems	Base	$574,004	95.931400%	$550,650	$550,650	$0	$0
3 - Continuous Emission Monitoring Systems	Intermediate	$354,239	95.428700%	$338,046	$338,046	$0	$0
3 - Continuous Emission Monitoring Systems	Peaking	$151,356	95.183700%	$144,066	$144,066	$0	$0
5 - Maintenance of Stationary Above Ground Fuel Tanks	Base	$4,001	95.931400%	$3,839	$295	$3,543	$0
5 - Maintenance of Stationary Above Ground Fuel Tanks	General	$736,673	96.900100%	$713,837	$54,911	$658,926	$0
5 - Maintenance of Stationary Above Ground Fuel Tanks	Intermediate	$196,207	95.428700%	$187,237	$14,403	$172,835	$0
5 - Maintenance of Stationary Above Ground Fuel Tanks	Peaking	$651,041	95.183700%	$619,685	$47,668	$572,017	$0
7 - Relocate Turbine Lube Oil Underground Piping to Above Gr	Base	$0	95.931400%	$0	$0	$0	$0
8 - Oil Spill Cleanup/Response Equipment	Distribution	$261	100.000000%	$261	$0	$0	$261
8 - Oil Spill Cleanup/Response Equipment	General	$326	96.900100%	$316	$24	$291	$0
8 - Oil Spill Cleanup/Response Equipment	Intermediate	$132,439	95.428700%	$126,385	$9,722	$116,663	$0
8 - Oil Spill Cleanup/Response Equipment	Peaking	$58,614	95.183700%	$55,791	$4,292	$51,499	$0
10 - Relocate Storm Water Runoff	Base	$5,868	95.931400%	$5,629	$433	$5,196	$0
12 - Scherer Discharge Pipeline	Base	$26,821	95.931400%	$25,730	$1,979	$23,751	$0
19 - Oil-filled Equipment and Hazardous Substance Remediatio	Distribution	$458,041	100.000000%	$458,041	$0	$0	$458,041
19 - Oil-filled Equipment and Hazardous Substance Remediatio	Transmission	$81,700	90.258100%	$73,741	$0	$73,741	$0
20 - Wastewater Discharge Elimination & Reuse	Peaking	$68,935	95.183700%	$65,615	$5,047	$60,568	$0
21 - St. Lucie Turtle Nets	Base	$723,372	95.931400%	$693,941	$53,380	$640,561	$0
22 - Pipeline Integrity Management	Intermediate	$138,966	95.428700%	$132,614	$10,201	$122,413	$0
22 - Pipeline Integrity Management	Peaking	$119,321	95.183700%	$113,574	$8,736	$104,838	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Base	$458,496	95.931400%	$439,842	$33,834	$406,008	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Distribution	$257,887	100.000000%	$257,887	$0	$0	$257,887
23 - SPCC - Spill Prevention, Control & Countermeasures	General	$22,421	96.900100%	$21,726	$1,671	$20,055	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Intermediate	$762,437	95.428700%	$727,584	$55,968	$671,616	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Peaking	$516,109	95.183700%	$491,251	$37,789	$453,463	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Transmission	$363,946	90.258100%	$328,491	$0	$328,491	$0
24 - Manatee Reburn	Peaking	$2,049,056	95.183700%	$1,950,368	$1,950,368	$0	$0
26 - UST Remove/Replacement	General	$6,487	96.900100%	$6,286	$484	$5,803	$0
27 - Lowest Quality Water Source	Base	$1,617,707	95.931400%	$1,551,889	$119,376	$1,432,513	$0
27 - Lowest Quality Water Source	Intermediate	$3,575,197	95.428700%	$3,411,764	$262,443	$3,149,321	$0
28 - CWA 316(b) Phase II Rule	Intermediate	$567,623	95.428700%	$541,676	$41,667	$500,008	$0
34 - St Lucie Cooling Water System Inspection & Maintenance	Base	$404,389	95.931400%	$387,936	$29,841	$358,095	$0
35 - Martin Plant Drinking Water System Compliance	Intermediate	$13,080	95.428700%	$12,482	$960	$11,522	$0
35 - Martin Plant Drinking Water System Compliance	Peaking	$9,868	95.183700%	$9,392	$722	$8,670	$0
36 - Low-Level Radioactive Waste Storage	Base	$1,603,192	95.931400%	$1,537,965	$118,305	$1,419,660	$0
37 - DeSoto Next Generation Solar Energy Center	Solar	$11,059,540	95.931400%	$10,609,572	$816,121	$9,793,451	$0
38 - Space Coast Next Generation Solar Energy Center	Solar	$5,154,426	95.931400%	$4,944,713	$380,363	$4,564,350	$0
39 - Martin Next Generation Solar Energy Center	Intermediate	$32,352,118	95.428700%	$30,873,206	$2,374,862	$28,498,344	$0
41 - Manatee Temporary Heating System	Distribution	$18,601	100.000000%	$18,601	$0	$0	$18,601

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered
Capital Projects

Form 42-3P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
		Monthly Data	Jurisdictionalization		Method of Classification		
Capital Projects	Strata	Twelve Month Total	Jurisdictional Factor	Juris Twelve Month Amount	Energy	CP Demand	GCP Demand
41 - Manatee Temporary Heating System	Intermediate	$2,960,225	95.428700%	$2,824,904	$217,300	$2,607,604	$0
41 - Manatee Temporary Heating System	Transmission	$0	90.258100%	$0	$0	$0	$0
42 - Turkey Point Cooling Canal Monitoring Plan	Base	$7,467,893	95.931400%	$7,164,054	$551,081	$6,612,973	$0
44 - Martin Plant Barley Barber Swamp Iron Mitigation	Intermediate	$8,083	95.428700%	$7,713	$0	$7,713	$0
44 - Martin Plant Barley Barber Swamp Iron Mitigation	Peaking	$6,098	95.183700%	$5,804	$0	$5,804	$0
47 - NPDES Permit Renewal Requirements	Base	$1,666,452	95.931400%	$1,598,651	$0	$1,598,651	$0
47 - NPDES Permit Renewal Requirements	Intermediate	$434,043	95.428700%	$414,201	$0	$414,201	$0
50 - Steam Electric Effluent Guidelines Revised Rules	Base	$754,942	95.931400%	$724,227	$55,710	$668,517	$0
54 - Coal Combustion Residuals	Base	$34,326,705	95.931400%	$32,930,088	$2,533,084	$30,397,005	$0
54 - Coal Combustion Residuals	Intermediate	$10,972,382	95.428700%	$10,470,802	$805,446	$9,665,355	$0
123 - The Protected Species Project	Intermediate	$185,636	95.428700%	$177,150	$0	$177,150	$0
124 - FPL Miami-Dade Clean Water Recovery Center	Intermediate	$1,025,717	95.428700%	$978,828	$0	$978,828	$0
401 - Air Quality Assurance Testing	Base	$16,076	95.931400%	$15,422	$1,186	$14,235	$0
402 - Crist 5, 6 & 7 Precipitator Projects	Base	$3,044,987	95.931400%	$2,921,098	$224,700	$2,696,399	$0
403 - Crist 7 Flue Gas Conditioning	Base	$122,480	95.931400%	$117,496	$9,038	$108,458	$0
408 - Crist Cooling Tower Cell	Base	$43,453	95.931400%	$41,685	$3,207	$38,479	$0
410 - Crist Diesel Fuel Oil Remediation	Base	$1,050	95.931400%	$1,008	$78	$930	$0
413 - Sodium Injection System	Base	$11,007	95.931400%	$10,559	$812	$9,747	$0
414 - Smith Stormwater Collection System	Intermediate	$150,575	95.428700%	$143,691	$11,053	$132,638	$0
415 - Smith Waste Water Treatment Facility	Intermediate	$89,631	95.428700%	$85,534	$6,580	$78,954	$0
416 - Daniel Ash Management Project	Base	$1,018,936	95.931400%	$977,480	$75,191	$902,289	$0
419 - Crist FDEP Agreement for Ozone Attainment	Base	$7,862,030	95.931400%	$7,542,155	$580,166	$6,961,989	$0
422 - Precipitator Upgrades for CAM Compliance	Base	$623,520	95.931400%	$598,151	$46,012	$552,140	$0
426 - Air Quality Compliance Program	Base	$159,625,802	95.931400%	$153,131,266	$11,779,328	$141,351,938	$0
426 - Air Quality Compliance Program	Distribution	$99	100.000000%	$99	$0	$0	$99
426 - Air Quality Compliance Program	General	$771	96.900100%	$747	$57	$690	$0
426 - Air Quality Compliance Program	Intermediate	$121,825	95.428700%	$116,256	$8,943	$107,313	$0
426 - Air Quality Compliance Program	Peaking	$30,745,235	95.183700%	$29,264,452	$2,251,112	$27,013,340	$0
426 - Air Quality Compliance Program	Transmission	$505,192	90.258100%	$455,976	$0	$455,976	$0
427 - General Water Quality	Base	$2,203,075	95.931400%	$2,113,440	$162,572	$1,950,868	$0
NA-Amortization of Gains on Sales of Emissions Allowances	Base	$513,872	95.931400%	$492,964	$0	$492,964	$0
Smith Units 1 & 2 Reg Asset	Base	$2,701,598	95.931400%	$2,591,680	$199,360	$2,392,320	$0
	Total	$336,234,576		$322,008,846	$28,650,278	$292,623,679	$734,889

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered
Capital Projects

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
1. Total of Capital Projects	$26,648,479	$28,010,585	$28,018,158	$28,027,641	$28,027,353	$28,024,231	$28,044,445	$28,065,827	$28,086,505	$28,282,455	$28,471,219	$28,527,677	$336,234,576
2. Recoverable Costs Jurisdictionalized on Energy													
Production - Base	$42,822	$42,822	$42,823	$42,823	$42,823	$42,823	$42,823	$42,823	$42,823	$42,823	$42,823	$42,823	$513,872
3. Recoverable Costs Jurisdictionalized on Demand													
Production - Base	$17,996,515	$19,231,628	$19,217,233	$19,197,259	$19,179,435	$19,157,671	$19,138,433	$19,119,073	$19,109,244	$19,098,781	$19,070,912	$19,070,693	$228,586,879
Production - Intermediate	$4,230,666	$4,247,936	$4,282,767	$4,324,483	$4,353,673	$4,383,850	$4,434,848	$4,487,054	$4,528,421	$4,746,282	$4,975,544	$5,044,899	$54,040,423
Production - Peaking	$2,797,342	$2,911,637	$2,903,527	$2,896,182	$2,889,184	$2,882,102	$2,875,005	$2,867,991	$2,861,787	$2,855,185	$2,847,436	$2,839,651	$34,427,030
Production - Solar	$1,376,624	$1,371,985	$1,367,274	$1,362,586	$1,358,006	$1,353,426	$1,348,849	$1,344,273	$1,339,658	$1,335,043	$1,330,428	$1,325,813	$16,213,966
General	$63,747	$64,018	$64,180	$64,157	$64,083	$64,008	$63,934	$63,859	$63,785	$63,710	$63,636	$63,561	$766,679
Transmission	$80,081	$79,927	$79,774	$79,620	$79,467	$79,313	$79,160	$79,006	$78,853	$78,699	$78,546	$78,392	$950,837
Distribution	$60,682	$60,632	$60,581	$60,530	$60,683	$61,038	$61,393	$61,748	$61,934	$61,931	$61,894	$61,844	$734,889
4. Retail Demand Jurisdictional Factors													
Production - Base	95.931400%	95.931400%	95.931400%	95.931400%	95.931400%	95.931400%	95.931400%	95.931400%	95.931400%	95.931400%	95.931400%	95.931400%	
Production - Intermediate	95.428700%	95.428700%	95.428700%	95.428700%	95.428700%	95.428700%	95.428700%	95.428700%	95.428700%	95.428700%	95.428700%	95.428700%	
Production - Peaking	95.183700%	95.183700%	95.183700%	95.183700%	95.183700%	95.183700%	95.183700%	95.183700%	95.183700%	95.183700%	95.183700%	95.183700%	
Production - Solar	95.931400%	95.931400%	95.931400%	95.931400%	95.931400%	95.931400%	95.931400%	95.931400%	95.931400%	95.931400%	95.931400%	95.931400%	
General	96.900100%	96.900100%	96.900100%	96.900100%	96.900100%	96.900100%	96.900100%	96.900100%	96.900100%	96.900100%	96.900100%	96.900100%	
Transmission	90.258100%	90.258100%	90.258100%	90.258100%	90.258100%	90.258100%	90.258100%	90.258100%	90.258100%	90.258100%	90.258100%	90.258100%	
Distribution	100.000000%	100.000000%	100.000000%	100.000000%	100.000000%	100.000000%	100.000000%	100.000000%	100.000000%	100.000000%	100.000000%	100.000000%	
5. Jurisdictional Recoverable Costs													
Production - Base	$17,305,389	$18,490,250	$18,476,441	$18,457,280	$18,440,181	$18,419,302	$18,400,847	$18,382,275	$18,372,846	$18,362,809	$18,336,074	$18,335,864	$219,779,558
Production - Intermediate	$4,037,269	$4,053,750	$4,086,988	$4,126,798	$4,154,653	$4,183,451	$4,232,118	$4,281,937	$4,321,413	$4,529,315	$4,748,097	$4,814,282	$51,570,073
Production - Peaking	$2,662,613	$2,771,404	$2,763,684	$2,756,694	$2,750,032	$2,743,292	$2,736,536	$2,729,860	$2,723,955	$2,717,670	$2,710,295	$2,702,885	$32,768,921
Production - Solar	$1,320,615	$1,316,165	$1,311,645	$1,307,148	$1,302,754	$1,298,360	$1,293,970	$1,289,580	$1,285,153	$1,280,725	$1,276,298	$1,271,871	$15,554,284
General	$61,771	$62,033	$62,190	$62,168	$62,096	$62,024	$61,952	$61,880	$61,808	$61,735	$61,663	$61,591	$742,913
Transmission	$72,279	$72,141	$72,002	$71,864	$71,725	$71,587	$71,448	$71,309	$71,171	$71,032	$70,894	$70,755	$858,208
Distribution	$60,682	$60,632	$60,581	$60,530	$60,683	$61,038	$61,393	$61,748	$61,934	$61,931	$61,894	$61,844	$734,889
6. Total Jurisdictional Recoverable Costs for Capital Projects	$25,520,619	$26,826,374	$26,833,533	$26,842,482	$26,842,125	$26,839,054	$26,858,264	$26,878,589	$26,898,280	$27,085,219	$27,265,216	$27,319,092	$322,008,846

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
2 - Low NOX Burner Technology														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$8,749,918	$8,749,918	$8,749,918	$8,749,918	$8,749,918	$8,749,918	$8,749,918	$8,749,918	$8,749,918	$8,749,918	$8,749,918	$8,749,918	$8,749,918	
3. Less: Accumulated Depreciation	($7,520,626)	($7,490,227)	($7,459,829)	($7,429,430)	($7,399,032)	($7,368,633)	($7,338,234)	($7,307,836)	($7,277,437)	($7,247,038)	($7,216,640)	($7,186,241)	($7,155,843)	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$16,270,544	$16,240,145	$16,209,747	$16,179,348	$16,148,950	$16,118,551	$16,088,152	$16,057,754	$16,027,355	$15,996,956	$15,966,558	$15,936,159	$15,905,761	
6. Average Net Investment		$16,255,345	$16,224,946	$16,194,547	$16,164,149	$16,133,750	$16,103,352	$16,072,953	$16,042,554	$16,012,156	$15,981,757	$15,951,359	$15,920,960	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$94,595	$94,418	$94,241	$94,064	$93,887	$93,710	$93,533	$93,356	$93,180	$93,003	$92,826	$92,649	$1,123,462
b. Debt Component (Line 6 x debt rate) (c) (f)		$16,064	$16,033	$16,003	$15,973	$15,943	$15,913	$15,883	$15,853	$15,823	$15,793	$15,763	$15,733	$190,780
8. Investment Expenses														
a. Depreciation (d)		$30,399	$30,399	$30,399	$30,399	$30,399	$30,399	$30,399	$30,399	$30,399	$30,399	$30,399	$30,399	$364,783
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$141,057	$140,850	$140,643	$140,436	$140,229	$140,022	$139,815	$139,608	$139,401	$139,194	$138,988	$138,781	$1,679,025

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
2 - Low NOX Burner Technology														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3. Less: Accumulated Depreciation	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	
a. Less: Capital Recovery Unamortized Balance	($187,914)	($184,782)	($181,650)	($178,518)	($175,386)	($172,254)	($169,122)	($165,990)	($162,858)	($159,726)	($156,595)	($153,463)	($150,331)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$187,914	$184,782	$181,650	$178,518	$175,386	$172,254	$169,122	$165,991	$162,859	$159,727	$156,595	$153,463	$150,331	
6. Average Net Investment		$186,348	$183,216	$180,084	$176,952	$173,820	$170,688	$167,557	$164,425	$161,293	$158,161	$155,029	$151,897	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$1,084	$1,066	$1,048	$1,030	$1,012	$993	$975	$957	$939	$920	$902	$884	$11,810
b. Debt Component (Line 6 x debt rate) (c) (f)		$184	$181	$178	$175	$172	$169	$166	$162	$159	$156	$153	$150	$2,006
8. Investment Expenses														
a. Depreciation (d)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization (e)		$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$37,583
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$4,400	$4,379	$4,358	$4,337	$4,315	$4,294	$4,273	$4,251	$4,230	$4,209	$4,187	$4,166	$51,398

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
3 - Continuous Emission Monitoring Systems														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		($515,653)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($515,653)
c. Retirements		($515,653)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($515,653)
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$81,182	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$81,182
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
h. Regulatory Assets		$81,182	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$81,182
2. Plant-In-Service/Depreciation Base (a)	$5,228,436	$4,712,783	$4,712,783	$4,712,783	$4,712,783	$4,712,783	$4,712,783	$4,712,783	$4,712,783	$4,712,783	$4,712,783	$4,712,783	$4,712,783	
3. Less: Accumulated Depreciation	$532,511	$113,856	$129,072	$144,289	$159,506	$174,722	$189,939	$205,155	$220,372	$235,589	$250,805	$266,022	$281,238	
a. Less: Capital Recovery Unamortized Balance	($62,603)	($143,263)	($142,403)	($141,543)	($140,683)	($139,823)	($138,963)	($138,103)	($137,243)	($136,383)	($135,523)	($134,663)	($133,803)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$4,758,528	$4,742,190	$4,726,113	$4,710,037	$4,693,960	$4,677,884	$4,661,807	$4,645,731	$4,629,654	$4,613,578	$4,597,501	$4,581,424	$4,565,348	
6. Average Net Investment		$4,750,359	$4,734,152	$4,718,075	$4,701,999	$4,685,922	$4,669,846	$4,653,769	$4,637,692	$4,621,616	$4,605,539	$4,589,463	$4,573,386	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$27,644	$27,549	$27,456	$27,362	$27,269	$27,175	$27,082	$26,988	$26,895	$26,801	$26,707	$26,614	$325,542
b. Debt Component (Line 6 x debt rate) (c) (f)		$4,694	$4,678	$4,662	$4,647	$4,631	$4,615	$4,599	$4,583	$4,567	$4,551	$4,535	$4,519	$55,282
8. Investment Expenses														
a. Depreciation (d)		$15,816	$15,217	$15,217	$15,217	$15,217	$15,217	$15,217	$15,217	$15,217	$15,217	$15,217	$15,217	$183,199
b. Amortization (e)		$522	$860	$860	$860	$860	$860	$860	$860	$860	$860	$860	$860	$9,981
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$48,676	$48,304	$48,195	$48,085	$47,976	$47,867	$47,757	$47,648	$47,538	$47,429	$47,319	$47,210	$574,004

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.

(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.

(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.

(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.

(e) Applicable amortization period(s). See Depreciation Schedule 4P.

(f) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
3 - Continuous Emission Monitoring Systems														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$329,059	$329,568	$291,005	$0	$0	$0	$0	$700,854	$0	$0	$1,650,486
b. Clearings to Plant		($28,196)	$0	$0	$38,054	$911,578	$0	$0	$0	$0	$0	$0	$700,854	$1,622,290
c. Retirements		($28,196)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($28,196)
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$273,310	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$273,310
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
h. Regulatory Assets		$273,310	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$273,310
2. Plant-In-Service/Depreciation Base (a)	$2,291,141	$2,262,945	$2,262,945	$2,262,945	$2,300,999	$3,212,577	$3,212,577	$3,212,577	$3,212,577	$3,212,577	$3,212,577	$3,212,577	$3,913,431	
3. Less: Accumulated Depreciation	$707,600	$960,367	$967,930	$975,493	$983,127	$992,154	$1,002,503	$1,012,851	$1,023,200	$1,033,548	$1,043,896	$1,054,245	$1,065,779	
a. Less: Capital Recovery Unamortized Balance	($145,040)	($415,186)	($411,958)	($408,730)	($405,503)	($402,275)	($399,047)	($395,819)	($392,591)	($389,363)	($386,136)	($382,908)	($379,680)	
4. CWIP	$0	$0	$0	$329,059	$620,573	$0	$0	$0	$0	$0	$700,854	$700,854	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,728,580	$1,717,764	$1,706,973	$2,025,241	$2,343,947	$2,622,698	$2,609,121	$2,595,545	$2,581,969	$2,568,393	$3,255,670	$3,242,094	$3,227,332	
6. Average Net Investment		$1,723,172	$1,712,369	$1,866,107	$2,184,594	$2,483,322	$2,615,909	$2,602,333	$2,588,757	$2,575,181	$2,912,032	$3,248,882	$3,234,713	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$10,028	$9,965	$10,859	$12,713	$14,451	$15,223	$15,144	$15,065	$14,986	$16,946	$18,906	$18,824	$173,109
b. Debt Component (Line 6 x debt rate) (c) (f)		$1,703	$1,692	$1,844	$2,159	$2,454	$2,585	$2,572	$2,558	$2,545	$2,878	$3,211	$3,197	$29,396
8. Investment Expenses														
a. Depreciation (d)		$7,653	$7,563	$7,563	$7,634	$9,027	$10,348	$10,348	$10,348	$10,348	$10,348	$10,348	$11,534	$113,064
b. Amortization (e)		$3,164	$3,228	$3,228	$3,228	$3,228	$3,228	$3,228	$3,228	$3,228	$3,228	$3,228	$3,228	$38,670
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$22,547	$22,448	$23,494	$25,734	$29,160	$31,384	$31,292	$31,199	$31,107	$33,400	$35,693	$36,782	$354,239

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
3 - Continuous Emission Monitoring Systems														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		($1,043,405)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1,043,405)
c. Retirements		($1,043,405)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1,043,405)
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$782,959	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$782,959
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
h. Regulatory Assets		$782,959	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$782,959
2. Plant-In-Service/Depreciation Base (a)	$1,200,749	$157,344	$157,344	$157,344	$157,344	$157,344	$157,344	$157,344	$157,344	$157,344	$157,344	$157,344	$157,344	
3. Less: Accumulated Depreciation	$285,311	$27,397	$27,932	$28,466	$29,001	$29,535	$30,070	$30,604	$31,139	$31,674	$32,208	$32,743	$33,277	
a. Less: Capital Recovery Unamortized Balance	($105,331)	($884,642)	($879,295)	($873,949)	($868,602)	($863,255)	($857,908)	($852,561)	($847,215)	($841,868)	($836,521)	($831,174)	($825,828)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,020,769	$1,014,589	$1,008,708	$1,002,826	$996,945	$991,064	$985,182	$979,301	$973,419	$967,538	$961,657	$955,775	$949,894	
6. Average Net Investment		$1,017,679	$1,011,648	$1,005,767	$999,886	$994,004	$988,123	$982,241	$976,360	$970,479	$964,597	$958,716	$952,835	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$5,922	$5,887	$5,853	$5,819	$5,784	$5,750	$5,716	$5,682	$5,648	$5,613	$5,579	$5,545	$68,798
b. Debt Component (Line 6 x debt rate) (c) (f)		$1,006	$1,000	$994	$988	$982	$976	$971	$965	$959	$953	$947	$942	$11,683
8. Investment Expenses														
a. Depreciation (d)		$2,532	$535	$535	$535	$535	$535	$535	$535	$535	$535	$535	$535	$8,413
b. Amortization (e)		$3,648	$5,347	$5,347	$5,347	$5,347	$5,347	$5,347	$5,347	$5,347	$5,347	$5,347	$5,347	$62,462
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$13,108	$12,768	$12,728	$12,688	$12,648	$12,608	$12,568	$12,528	$12,488	$12,448	$12,408	$12,368	$151,356

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.

(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.

(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.

(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.

(e) Applicable amortization period(s). See Depreciation Schedule 4P.

(f) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
5 - Maintenance of Stationary Above Ground Fuel Tanks														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3. Less: Accumulated Depreciation	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	
a. Less: Capital Recovery Unamortized Balance	($22,529)	($22,342)	($22,154)	($21,966)	($21,778)	($21,591)	($21,403)	($21,215)	($21,027)	($20,840)	($20,652)	($20,464)	($20,276)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$22,529	$22,342	$22,154	$21,966	$21,778	$21,591	$21,403	$21,215	$21,027	$20,840	$20,652	$20,464	$20,276	
6. Average Net Investment		$22,435	$22,248	$22,060	$21,872	$21,684	$21,497	$21,309	$21,121	$20,934	$20,746	$20,558	$20,370	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$131	$129	$128	$127	$126	$125	$124	$123	$122	$121	$120	$119	$1,495
b. Debt Component (Line 6 x debt rate) (c) (f)		$22	$22	$22	$22	$21	$21	$21	$21	$21	$21	$20	$20	$254
8. Investment Expenses														
a. Depreciation (d)		($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
b. Amortization (e)		$188	$188	$188	$188	$188	$188	$188	$188	$188	$188	$188	$188	$2,253
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$340	$339	$338	$337	$335	$334	$333	$332	$330	$329	$328	$326	$4,001

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
5 - Maintenance of Stationary Above Ground Fuel Tanks														
General														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$8,225,223	$8,225,223	$8,225,223	$8,225,223	$8,225,223	$8,225,223	$8,225,223	$8,225,223	$8,225,223	$8,225,223	$8,225,223	$8,225,223	$8,225,223	
3. Less: Accumulated Depreciation	$655,948	$666,230	$676,511	$686,793	$697,074	$707,356	$717,638	$727,919	$738,201	$748,482	$758,764	$769,045	$779,327	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$7,569,274	$7,558,993	$7,548,711	$7,538,430	$7,528,148	$7,517,867	$7,507,585	$7,497,304	$7,487,022	$7,476,740	$7,466,459	$7,456,177	$7,445,896	
6. Average Net Investment		$7,564,133	$7,553,852	$7,543,570	$7,533,289	$7,523,007	$7,512,726	$7,502,444	$7,492,163	$7,481,881	$7,471,600	$7,461,318	$7,451,037	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$44,018	$43,958	$43,898	$43,838	$43,779	$43,719	$43,659	$43,599	$43,539	$43,479	$43,420	$43,360	$524,267
b. Debt Component (Line 6 x debt rate) (c) (f)		$7,475	$7,465	$7,455	$7,444	$7,434	$7,424	$7,414	$7,404	$7,394	$7,383	$7,373	$7,363	$89,028
8. Investment Expenses														
a. Depreciation (d)		$10,282	$10,282	$10,282	$10,282	$10,282	$10,282	$10,282	$10,282	$10,282	$10,282	$10,282	$10,282	$123,378
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$61,774	$61,704	$61,634	$61,564	$61,494	$61,424	$61,354	$61,284	$61,214	$61,144	$61,074	$61,004	$736,673

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
5 - Maintenance of Stationary Above Ground Fuel Tanks														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		($1,412,190)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1,412,190)
c. Retirements		($1,412,190)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1,412,190)
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$699,792	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$699,792
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
h. Regulatory Assets		$699,792	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$699,792
2. Plant-In-Service/Depreciation Base (a)	$2,263,300	$851,110	$851,110	$851,110	$851,110	$851,110	$851,110	$851,110	$851,110	$851,110	$851,110	$851,110	$851,110	
3. Less: Accumulated Depreciation	$1,147,416	$438,959	$440,896	$442,834	$444,771	$446,708	$448,645	$450,582	$452,519	$454,456	$456,393	$458,330	$460,267	
a. Less: Capital Recovery Unamortized Balance	($185,394)	($880,906)	($875,067)	($869,229)	($863,390)	($857,552)	($851,714)	($845,875)	($840,037)	($834,198)	($828,360)	($822,521)	($816,683)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,301,277	$1,293,056	$1,285,281	$1,277,505	$1,269,730	$1,261,954	$1,254,179	$1,246,403	$1,238,628	$1,230,852	$1,223,077	$1,215,301	$1,207,526	
6. Average Net Investment		$1,297,166	$1,289,168	$1,281,393	$1,273,617	$1,265,842	$1,258,066	$1,250,291	$1,242,515	$1,234,740	$1,226,964	$1,219,189	$1,211,413	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$7,549	$7,502	$7,457	$7,412	$7,366	$7,321	$7,276	$7,231	$7,185	$7,140	$7,095	$7,050	$87,583
b. Debt Component (Line 6 x debt rate) (c) (f)		$1,282	$1,274	$1,266	$1,259	$1,251	$1,243	$1,236	$1,228	$1,220	$1,212	$1,205	$1,197	$14,873
8. Investment Expenses														
a. Depreciation (d)		$3,941	$1,937	$1,937	$1,937	$1,937	$1,937	$1,937	$1,937	$1,937	$1,937	$1,937	$1,937	$25,249
b. Amortization (e)		$4,279	$5,838	$5,838	$5,838	$5,838	$5,838	$5,838	$5,838	$5,838	$5,838	$5,838	$5,838	$68,502
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$17,051	$16,552	$16,499	$16,446	$16,393	$16,340	$16,287	$16,234	$16,181	$16,128	$16,075	$16,022	$196,207

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
5 - Maintenance of Stationary Above Ground Fuel Tanks														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		($2,105,891)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($2,105,891)
c. Retirements		($2,105,891)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($2,105,891)
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$1,429,294	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,429,294
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
h. Regulatory Assets		$1,429,294	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,429,294
2. Plant-In-Service/Depreciation Base (a)	$3,410,311	$1,304,419	$1,304,419	$1,304,419	$1,304,419	$1,304,419	$1,304,419	$1,304,419	$1,304,419	$1,304,419	$1,304,419	$1,304,419	$1,304,419	
3. Less: Accumulated Depreciation	$1,634,420	$965,612	$970,275	$974,937	$979,600	$984,262	$988,925	$993,587	$998,249	$1,002,912	$1,007,574	$1,012,237	$1,016,899	
a. Less: Capital Recovery Unamortized Balance	($1,392,925)	($2,795,084)	($2,765,747)	($2,736,410)	($2,707,073)	($2,677,736)	($2,648,399)	($2,619,062)	($2,589,726)	($2,560,389)	($2,531,052)	($2,501,715)	($2,472,378)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$3,168,816	$3,133,891	$3,099,892	$3,065,892	$3,031,893	$2,997,894	$2,963,894	$2,929,895	$2,895,896	$2,861,896	$2,827,897	$2,793,898	$2,759,898	
6. Average Net Investment		$3,151,353	$3,116,891	$3,082,892	$3,048,893	$3,014,893	$2,980,894	$2,946,895	$2,912,895	$2,878,896	$2,844,897	$2,810,897	$2,776,898	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$18,339	$18,138	$17,940	$17,742	$17,545	$17,347	$17,149	$16,951	$16,753	$16,555	$16,357	$16,160	$206,976
b. Debt Component (Line 6 x debt rate) (c) (f)		$3,114	$3,080	$3,047	$3,013	$2,979	$2,946	$2,912	$2,879	$2,845	$2,811	$2,778	$2,744	$35,148
8. Investment Expenses														
a. Depreciation (d)		$7,789	$4,662	$4,662	$4,662	$4,662	$4,662	$4,662	$4,662	$4,662	$4,662	$4,662	$4,662	$59,076
b. Amortization (e)		$27,135	$29,337	$29,337	$29,337	$29,337	$29,337	$29,337	$29,337	$29,337	$29,337	$29,337	$29,337	$349,841
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$56,377	$55,218	$54,986	$54,755	$54,523	$54,292	$54,060	$53,829	$53,597	$53,366	$53,135	$52,903	$651,041

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
7 - Relocate Turbine Lube Oil Underground Piping to Above Ground														
Base														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	
3. Less: Accumulated Depreciation	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
6. Average Net Investment		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Debt Component (Line 6 x debt rate) (c)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8. Investment Expenses														
a. Depreciation (d)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
8 - Oil Spill Cleanup/Response Equipment														
Distribution														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	
3. Less: Accumulated Depreciation	$508	$513	$518	$523	$528	$533	$538	$543	$548	$553	$558	$563	$568	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$2,487	$2,482	$2,477	$2,472	$2,467	$2,462	$2,457	$2,452	$2,447	$2,442	$2,437	$2,432	$2,427	
6. Average Net Investment		$2,484	$2,479	$2,474	$2,469	$2,464	$2,459	$2,454	$2,449	$2,444	$2,439	$2,434	$2,429	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$14	$14	$14	$14	$14	$14	$14	$14	$14	$14	$14	$14	$172
b. Debt Component (Line 6 x debt rate) (c) (f)		$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$29
8. Investment Expenses														
a. Depreciation (d)		$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$60
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$261

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
8 - Oil Spill Cleanup/Response Equipment														
General														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	
3. Less: Accumulated Depreciation	$1,202	$1,207	$1,213	$1,218	$1,224	$1,229	$1,235	$1,240	$1,246	$1,252	$1,257	$1,263	$1,268	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$3,211	$3,205	$3,200	$3,194	$3,189	$3,183	$3,178	$3,172	$3,167	$3,161	$3,156	$3,150	$3,145	
6. Average Net Investment		$3,208	$3,203	$3,197	$3,192	$3,186	$3,181	$3,175	$3,170	$3,164	$3,158	$3,153	$3,147	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$19	$19	$19	$19	$19	$19	$18	$18	$18	$18	$18	$18	$222
b. Debt Component (Line 6 x debt rate) (c) (f)		$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$38
8. Investment Expenses														
a. Depreciation (d)		$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$66
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$27	$27	$27	$27	$27	$27	$27	$27	$27	$27	$27	$27	$326

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.

(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.

(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.

(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.

(e) Applicable amortization period(s). See Depreciation Schedule 4P.

(f) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
8 - Oil Spill Cleanup/Response Equipment														
Intermediate														
1. Investments														
a. Expenditures/Additions		$1,954	$1,954	$1,954	$1,954	$1,954	$1,954	$1,954	$1,954	$1,954	$1,954	$1,954	$1,954	$23,448
b. Clearings to Plant		($18,195)	($64,478)	$1,954	$1,954	$1,954	($16,568)	($1,659)	$1,954	$1,954	($8,597)	$1,954	($16,733)	($114,506)
c. Retirements		($20,149)	($66,432)	$0	$0	$0	($18,522)	($3,613)	$0	$0	($10,551)	$0	($18,687)	($137,954)
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$18,120	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$18,120
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
h. Regulatory Assets		$18,120	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$18,120
2. Plant-In-Service/Depreciation Base (a)	$1,028,866	$1,010,671	$946,193	$948,147	$950,102	$952,056	$935,488	$933,829	$935,783	$937,737	$929,140	$931,094	$914,361	
3. Less: Accumulated Depreciation	$29,735	$32,956	($28,774)	($24,593)	($20,380)	($16,133)	($30,487)	($30,030)	($25,950)	($21,837)	($28,306)	($24,253)	($38,967)	
a. Less: Capital Recovery Unamortized Balance	$110	($17,996)	($17,922)	($17,848)	($17,775)	($17,701)	($17,627)	($17,554)	($17,480)	($17,406)	($17,333)	($17,259)	($17,185)	
4. CWIP	$1,316	$1,316	$1,316	$1,316	$1,316	$1,316	$1,316	$1,316	$1,316	$1,316	$1,316	$1,316	$1,316	
5. Net Investment (Lines 2 - 3 + 4)	$1,000,338	$997,027	$994,206	$991,905	$989,572	$987,206	$984,918	$982,729	$980,529	$978,297	$976,095	$973,923	$971,829	
6. Average Net Investment		$998,683	$995,617	$993,055	$990,739	$988,389	$986,062	$983,824	$981,629	$979,413	$977,196	$975,009	$972,876	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$5,812	$5,794	$5,779	$5,765	$5,752	$5,738	$5,725	$5,712	$5,700	$5,687	$5,674	$5,661	$68,799
b. Debt Component (Line 6 x debt rate) (c) (f)		$987	$984	$981	$979	$977	$974	$972	$970	$968	$966	$964	$961	$11,683
8. Investment Expenses														
a. Depreciation (d)		$5,250	$4,702	$4,181	$4,214	$4,246	$4,168	$4,069	$4,080	$4,113	$4,083	$4,052	$3,974	$51,132
b. Amortization (e)		$15	$74	$74	$74	$74	$74	$74	$74	$74	$74	$74	$74	$825
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$12,063	$11,553	$11,015	$11,032	$11,048	$10,955	$10,840	$10,836	$10,854	$10,809	$10,763	$10,670	$132,439

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
8 - Oil Spill Cleanup/Response Equipment														
Peaking														
1. Investments														
a. Expenditures/Additions		$1,474	$1,474	$1,474	$1,474	$1,474	$1,474	$1,474	$1,474	$1,474	$1,474	$1,474	$1,474	$17,689
b. Clearings to Plant		($77,740)	($48,641)	$1,474	$1,474	$1,474	($12,498)	($1,251)	$1,474	$1,474	($6,486)	$1,474	($12,623)	($150,395)
c. Retirements		($79,214)	($50,115)	$0	$0	$0	($13,972)	($2,726)	$0	$0	($7,960)	$0	($14,098)	($168,085)
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$74,147	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$74,147
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
h. Regulatory Assets		$74,147	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$74,147
2. Plant-In-Service/Depreciation Base (a)	$468,560	$390,819	$342,178	$343,652	$345,127	$346,601	$334,102	$332,851	$334,325	$335,799	$329,313	$330,788	$318,164	
3. Less: Accumulated Depreciation	$147,288	$145,494	$98,186	$100,600	$103,038	$105,501	$93,933	$93,537	$95,875	$98,238	$92,618	$94,935	$83,095	
a. Less: Capital Recovery Unamortized Balance	$0	($74,134)	($73,826)	($73,517)	($73,208)	($72,899)	($72,590)	($72,281)	($71,972)	($71,663)	($71,354)	($71,045)	($70,736)	
4. CWIP	($1,316)	($1,316)	($1,316)	($1,316)	($1,316)	($1,316)	($1,316)	($1,316)	($1,316)	($1,316)	($1,316)	($1,316)	($1,316)	
5. Net Investment (Lines 2 - 3 + 4)	$319,955	$318,143	$316,502	$315,253	$313,980	$312,682	$311,442	$310,278	$309,105	$307,908	$306,733	$305,582	$304,489	
6. Average Net Investment		$319,049	$317,322	$315,877	$314,616	$313,331	$312,062	$310,860	$309,692	$308,507	$307,321	$306,158	$305,036	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$1,857	$1,847	$1,838	$1,831	$1,823	$1,816	$1,809	$1,802	$1,795	$1,788	$1,782	$1,775	$21,763
b. Debt Component (Line 6 x debt rate) (c) (f)		$315	$314	$312	$311	$310	$308	$307	$306	$305	$304	$303	$301	$3,696
8. Investment Expenses														
a. Depreciation (d)		$3,273	$2,807	$2,414	$2,438	$2,463	$2,404	$2,330	$2,338	$2,362	$2,340	$2,317	$2,258	$29,744
b. Amortization (e)		$13	$309	$309	$309	$309	$309	$309	$309	$309	$309	$309	$309	$3,411
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$5,458	$5,276	$4,873	$4,889	$4,905	$4,838	$4,755	$4,755	$4,772	$4,741	$4,710	$4,643	$58,614

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
10 - Relocate Storm Water Runoff														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	
3. Less: Accumulated Depreciation	$77,079	$77,300	$77,521	$77,741	$77,962	$78,183	$78,404	$78,625	$78,846	$79,067	$79,287	$79,508	$79,729	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$40,715	$40,494	$40,273	$40,052	$39,832	$39,611	$39,390	$39,169	$38,948	$38,727	$38,506	$38,285	$38,065	
6. Average Net Investment		$40,605	$40,384	$40,163	$39,942	$39,721	$39,500	$39,279	$39,058	$38,838	$38,617	$38,396	$38,175	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$236	$235	$234	$232	$231	$230	$229	$227	$226	$225	$223	$222	$2,751
b. Debt Component (Line 6 x debt rate) (c) (f)		$40	$40	$40	$39	$39	$39	$39	$39	$38	$38	$38	$38	$467
8. Investment Expenses														
a. Depreciation (d)		$221	$221	$221	$221	$221	$221	$221	$221	$221	$221	$221	$221	$2,650
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$497	$496	$494	$493	$491	$490	$488	$487	$485	$484	$482	$481	$5,868

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
12 - Scherer Discharge Pipeline														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		($854,324)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($854,324)
c. Retirements		($854,324)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($854,324)
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$208,116	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$208,116
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
h. Regulatory Assets		$208,116	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$208,116
2. Plant-In-Service/Depreciation Base (a)	$854,324	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3. Less: Accumulated Depreciation	$645,572	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
a. Less: Capital Recovery Unamortized Balance	$0	($208,116)	($207,249)	($206,381)	($205,514)	($204,647)	($203,780)	($202,913)	($202,046)	($201,179)	($200,311)	($199,444)	($198,577)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$208,752	$208,116	$207,249	$206,381	$205,514	$204,647	$203,780	$202,913	$202,046	$201,179	$200,311	$199,444	$198,577	
6. Average Net Investment		$208,434	$207,682	$206,815	$205,948	$205,081	$204,214	$203,346	$202,479	$201,612	$200,745	$199,878	$199,011	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$1,213	$1,209	$1,204	$1,198	$1,193	$1,188	$1,183	$1,178	$1,173	$1,168	$1,163	$1,158	$14,230
b. Debt Component (Line 6 x debt rate) (c) (f)		$206	$205	$204	$204	$203	$202	$201	$200	$199	$198	$198	$197	$2,416
8. Investment Expenses														
a. Depreciation (d)		$636	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$636
b. Amortization (e)		$0	$867	$867	$867	$867	$867	$867	$867	$867	$867	$867	$867	$9,539
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$2,055	$2,281	$2,275	$2,269	$2,263	$2,257	$2,251	$2,246	$2,240	$2,234	$2,228	$2,222	$26,821

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
19 - Oil-filled Equipment and Hazardous Substance Remediation														
Distribution														
1. Investments														
a. Expenditures/Additions		$6,800	$6,800	$6,800	$6,800	$66,375	$66,375	$66,375	$66,375	$16,800	$10,800	$6,800	$6,800	$333,900
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$3,730,623	$3,730,623	$3,730,623	$3,730,623	$3,730,623	$3,730,623	$3,730,623	$3,730,623	$3,730,623	$3,730,623	$3,730,623	$3,730,623	$3,730,623	
3. Less: Accumulated Depreciation	($274,869)	($265,819)	($256,769)	($247,720)	($238,670)	($229,620)	($220,570)	($211,520)	($202,471)	($193,421)	($184,371)	($175,321)	($166,271)	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$162,790	$169,590	$176,390	$183,190	$189,990	$256,365	$322,740	$389,115	$455,490	$472,290	$483,090	$489,890	$496,690	
5. Net Investment (Lines 2 - 3 + 4)	$4,168,281	$4,166,032	$4,163,782	$4,161,532	$4,159,282	$4,216,608	$4,273,933	$4,331,258	$4,388,583	$4,396,333	$4,398,084	$4,395,834	$4,393,584	
6. Average Net Investment		$4,167,157	$4,164,907	$4,162,657	$4,160,407	$4,187,945	$4,245,270	$4,302,595	$4,359,921	$4,392,458	$4,397,208	$4,396,959	$4,394,709	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$24,250	$24,237	$24,224	$24,211	$24,371	$24,705	$25,038	$25,372	$25,561	$25,589	$25,587	$25,574	$298,718
b. Debt Component (Line 6 x debt rate) (c) (f)		$4,118	$4,116	$4,114	$4,111	$4,139	$4,195	$4,252	$4,308	$4,341	$4,345	$4,345	$4,343	$50,726
8. Investment Expenses														
a. Depreciation (d)		$9,050	$9,050	$9,050	$9,050	$9,050	$9,050	$9,050	$9,050	$9,050	$9,050	$9,050	$9,050	$108,597
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$37,418	$37,402	$37,387	$37,372	$37,559	$37,949	$38,340	$38,730	$38,951	$38,984	$38,982	$38,967	$458,041

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
19 - Oil-filled Equipment and Hazardous Substance Remediation														
Transmission														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$828,456	$828,456	$828,456	$828,456	$828,456	$828,456	$828,456	$828,456	$828,456	$828,456	$828,456	$828,456	$828,456	
3. Less: Accumulated Depreciation	$56,894	$58,516	$60,139	$61,761	$63,383	$65,005	$66,627	$68,249	$69,872	$71,494	$73,116	$74,738	$76,360	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$771,562	$769,940	$768,318	$766,696	$765,074	$763,451	$761,829	$760,207	$758,585	$756,963	$755,341	$753,718	$752,096	
6. Average Net Investment		$770,751	$769,129	$767,507	$765,885	$764,262	$762,640	$761,018	$759,396	$757,774	$756,152	$754,529	$752,907	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$4,485	$4,476	$4,466	$4,457	$4,447	$4,438	$4,429	$4,419	$4,410	$4,400	$4,391	$4,381	$53,200
b. Debt Component (Line 6 x debt rate) (c) (f)		$762	$760	$758	$757	$755	$754	$752	$750	$749	$747	$746	$744	$9,034
8. Investment Expenses														
a. Depreciation (d)		$1,622	$1,622	$1,622	$1,622	$1,622	$1,622	$1,622	$1,622	$1,622	$1,622	$1,622	$1,622	$19,466
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$6,869	$6,858	$6,847	$6,836	$6,825	$6,814	$6,803	$6,792	$6,781	$6,770	$6,759	$6,748	$81,700

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
20 - Wastewater Discharge Elimination & Reuse														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$531,712	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$531,712
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
h. Regulatory Assets		$531,712	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$531,712
2. Plant-In-Service/Depreciation Base (a)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3. Less: Accumulated Depreciation	($531,712)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
a. Less: Capital Recovery Unamortized Balance	$0	($529,497)	($527,282)	($525,066)	($522,851)	($520,635)	($518,420)	($516,204)	($513,989)	($511,773)	($509,558)	($507,342)	($505,127)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$531,712	$529,497	$527,282	$525,066	$522,851	$520,635	$518,420	$516,204	$513,989	$511,773	$509,558	$507,342	$505,127	
6. Average Net Investment		$530,605	$528,389	$526,174	$523,958	$521,743	$519,527	$517,312	$515,096	$512,881	$510,666	$508,450	$506,235	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$3,088	$3,075	$3,062	$3,049	$3,036	$3,023	$3,010	$2,998	$2,985	$2,972	$2,959	$2,946	$36,202
b. Debt Component (Line 6 x debt rate) (c) (f)		$524	$522	$520	$518	$516	$513	$511	$509	$507	$505	$502	$500	$6,148
8. Investment Expenses														
a. Depreciation (d)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization (e)		$2,215	$2,215	$2,215	$2,215	$2,215	$2,215	$2,215	$2,215	$2,215	$2,215	$2,215	$2,215	$26,586
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$5,828	$5,812	$5,797	$5,782	$5,767	$5,752	$5,737	$5,722	$5,707	$5,692	$5,677	$5,662	$68,935

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.

(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.

(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.

(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.

(e) Applicable amortization period(s). See Depreciation Schedule 4P.

(f) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
21 - St. Lucie Turtle Nets														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	
3. Less: Accumulated Depreciation	($120,146)	($107,191)	($94,235)	($81,280)	($68,324)	($55,369)	($42,413)	($29,458)	($16,503)	($3,547)	$9,408	$22,364	$35,319	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$7,029,705	$7,016,749	$7,003,794	$6,990,838	$6,977,883	$6,964,927	$6,951,972	$6,939,017	$6,926,061	$6,913,106	$6,900,150	$6,887,195	$6,874,239	
6. Average Net Investment		$7,023,227	$7,010,271	$6,997,316	$6,984,361	$6,971,405	$6,958,450	$6,945,494	$6,932,539	$6,919,583	$6,906,628	$6,893,673	$6,880,717	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$40,870	$40,795	$40,719	$40,644	$40,569	$40,493	$40,418	$40,343	$40,267	$40,192	$40,116	$40,041	$485,468
b. Debt Component (Line 6 x debt rate) (c) (f)		$6,940	$6,928	$6,915	$6,902	$6,889	$6,876	$6,864	$6,851	$6,838	$6,825	$6,812	$6,800	$82,439
8. Investment Expenses														
a. Depreciation (d)		$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$155,465
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$60,766	$60,678	$60,590	$60,501	$60,413	$60,325	$60,237	$60,149	$60,061	$59,972	$59,884	$59,796	$723,372

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
22 - Pipeline Integrity Management														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		($258,394)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($258,394)
c. Retirements		($258,394)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($258,394)
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$198,465	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$198,465
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
h. Regulatory Assets		$198,465	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$198,465
2. Plant-In-Service/Depreciation Base (a)	$1,553,191	$1,294,797	$1,294,797	$1,294,797	$1,294,797	$1,294,797	$1,294,797	$1,294,797	$1,294,797	$1,294,797	$1,294,797	$1,294,797	$1,294,797	
3. Less: Accumulated Depreciation	$346,192	$289,323	$292,043	$294,762	$297,481	$300,200	$302,919	$305,638	$308,357	$311,076	$313,795	$316,514	$319,233	
a. Less: Capital Recovery Unamortized Balance	$0	($198,465)	($197,638)	($196,812)	($195,985)	($195,158)	($194,331)	($193,504)	($192,677)	($191,850)	($191,023)	($190,196)	($189,369)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,207,000	$1,203,939	$1,200,393	$1,196,847	$1,193,301	$1,189,755	$1,186,209	$1,182,663	$1,179,117	$1,175,571	$1,172,025	$1,168,479	$1,164,933	
6. Average Net Investment		$1,205,469	$1,202,166	$1,198,620	$1,195,074	$1,191,528	$1,187,982	$1,184,436	$1,180,890	$1,177,344	$1,173,798	$1,170,252	$1,166,706	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$7,015	$6,996	$6,975	$6,954	$6,934	$6,913	$6,893	$6,872	$6,851	$6,831	$6,810	$6,789	$82,834
b. Debt Component (Line 6 x debt rate) (c) (f)		$1,191	$1,188	$1,184	$1,181	$1,177	$1,174	$1,170	$1,167	$1,163	$1,160	$1,156	$1,153	$14,066
8. Investment Expenses														
a. Depreciation (d)		$3,060	$2,719	$2,719	$2,719	$2,719	$2,719	$2,719	$2,719	$2,719	$2,719	$2,719	$2,719	$32,970
b. Amortization (e)		$0	$827	$827	$827	$827	$827	$827	$827	$827	$827	$827	$827	$9,096
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$11,267	$11,730	$11,706	$11,681	$11,657	$11,633	$11,609	$11,585	$11,561	$11,537	$11,513	$11,488	$138,966

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
22 - Pipeline Integrity Management														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		($342,823)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($342,823)
c. Retirements		($342,823)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($342,823)
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$263,313	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$263,313
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
h. Regulatory Assets		$263,313	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$263,313
2. Plant-In-Service/Depreciation Base (a)	$1,319,600	$976,777	$976,777	$976,777	$976,777	$976,777	$976,777	$976,777	$976,777	$976,777	$976,777	$976,777	$976,777	
3. Less: Accumulated Depreciation	$295,267	$218,262	$220,313	$222,364	$224,415	$226,466	$228,518	$230,569	$232,620	$234,671	$236,723	$238,774	$240,825	
a. Less: Capital Recovery Unamortized Balance	$0	($263,313)	($262,216)	($261,119)	($260,022)	($258,924)	($257,827)	($256,730)	($255,633)	($254,536)	($253,439)	($252,342)	($251,245)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,024,332	$1,021,828	$1,018,680	$1,015,532	$1,012,383	$1,009,235	$1,006,087	$1,002,938	$999,790	$996,642	$993,493	$990,345	$987,196	
6. Average Net Investment		$1,023,080	$1,020,254	$1,017,106	$1,013,958	$1,010,809	$1,007,661	$1,004,512	$1,001,364	$998,216	$995,067	$991,919	$988,771	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$5,954	$5,937	$5,919	$5,901	$5,882	$5,864	$5,846	$5,827	$5,809	$5,791	$5,772	$5,754	$70,255
b. Debt Component (Line 6 x debt rate) (c) (f)		$1,011	$1,008	$1,005	$1,002	$999	$996	$993	$990	$986	$983	$980	$977	$11,930
8. Investment Expenses														
a. Depreciation (d)		$2,504	$2,051	$2,051	$2,051	$2,051	$2,051	$2,051	$2,051	$2,051	$2,051	$2,051	$2,051	$25,068
b. Amortization (e)		$0	$1,097	$1,097	$1,097	$1,097	$1,097	$1,097	$1,097	$1,097	$1,097	$1,097	$1,097	$12,069
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$9,469	$10,094	$10,072	$10,051	$10,029	$10,008	$9,987	$9,965	$9,944	$9,922	$9,901	$9,879	$119,321

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
23 - SPCC - Spill Prevention, Control & Countermeasures														
Base														
1. Investments														
a. Expenditures/Additions		$257,000	$257,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$514,000
b. Clearings to Plant		$0	$0	$616,800	$0	$0	$0	$0	$0	$0	$0	$0	$0	$616,800
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$4,216,018	$4,216,018	$4,216,018	$4,832,818	$4,832,818	$4,832,818	$4,832,818	$4,832,818	$4,832,818	$4,832,818	$4,832,818	$4,832,818	$4,832,818	
3. Less: Accumulated Depreciation	$1,602,762	$1,618,298	$1,633,834	$1,650,398	$1,667,990	$1,685,582	$1,703,174	$1,720,766	$1,738,358	$1,755,951	$1,773,543	$1,791,135	$1,808,727	
a. Less: Capital Recovery Unamortized Balance	($5,073)	($5,073)	($5,073)	($5,073)	($5,073)	($5,073)	($5,073)	($5,073)	($5,073)	($5,073)	($5,073)	($5,073)	($5,073)	
4. CWIP	$102,800	$359,800	$616,800	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$2,721,129	$2,962,593	$3,204,057	$3,187,493	$3,169,901	$3,152,309	$3,134,716	$3,117,124	$3,099,532	$3,081,940	$3,064,348	$3,046,756	$3,029,164	
6. Average Net Investment		$2,841,861	$3,083,325	$3,195,775	$3,178,697	$3,161,105	$3,143,512	$3,125,920	$3,108,328	$3,090,736	$3,073,144	$3,055,552	$3,037,960	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$16,538	$17,943	$18,597	$18,498	$18,395	$18,293	$18,191	$18,088	$17,986	$17,884	$17,781	$17,679	$215,872
b. Debt Component (Line 6 x debt rate) (c) (f)		$2,808	$3,047	$3,158	$3,141	$3,124	$3,106	$3,089	$3,072	$3,054	$3,037	$3,019	$3,002	$36,658
8. Investment Expenses														
a. Depreciation (d)		$15,536	$15,536	$16,564	$17,592	$17,592	$17,592	$17,592	$17,592	$17,592	$17,592	$17,592	$17,592	$205,965
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$34,882	$36,526	$38,319	$39,231	$39,111	$38,992	$38,872	$38,752	$38,632	$38,513	$38,393	$38,273	$458,496

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
23 - SPCC - Spill Prevention, Control & Countermeasures														
Distribution														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$3,532,175	$3,532,175	$3,532,175	$3,532,175	$3,532,175	$3,532,175	$3,532,175	$3,532,175	$3,532,175	$3,532,175	$3,532,175	$3,532,175	$3,532,175	
3. Less: Accumulated Depreciation	$1,103,119	$1,108,284	$1,113,450	$1,118,616	$1,123,782	$1,128,948	$1,134,113	$1,139,279	$1,144,445	$1,149,611	$1,154,776	$1,159,942	$1,165,108	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$2,429,056	$2,423,890	$2,418,724	$2,413,559	$2,408,393	$2,403,227	$2,398,061	$2,392,896	$2,387,730	$2,382,564	$2,377,398	$2,372,233	$2,367,067	
6. Average Net Investment		$2,426,473	$2,421,307	$2,416,142	$2,410,976	$2,405,810	$2,400,644	$2,395,479	$2,390,313	$2,385,147	$2,379,981	$2,374,816	$2,369,650	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$14,120	$14,090	$14,060	$14,030	$14,000	$13,970	$13,940	$13,910	$13,880	$13,850	$13,820	$13,790	$167,461
b. Debt Component (Line 6 x debt rate) (c) (f)		$2,398	$2,393	$2,388	$2,383	$2,377	$2,372	$2,367	$2,362	$2,357	$2,352	$2,347	$2,342	$28,437
8. Investment Expenses														
a. Depreciation (d)		$5,166	$5,166	$5,166	$5,166	$5,166	$5,166	$5,166	$5,166	$5,166	$5,166	$5,166	$5,166	$61,989
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$21,684	$21,649	$21,614	$21,578	$21,543	$21,508	$21,473	$21,438	$21,403	$21,367	$21,332	$21,297	$257,887

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.

(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.

(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.

(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.

(e) Applicable amortization period(s). See Depreciation Schedule 4P.

(f) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
23 - SPCC - Spill Prevention, Control & Countermeasures														
General														
1. Investments														
a. Expenditures/Additions		$45,000	$51,750	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$96,750
b. Clearings to Plant		$11,250	$12,938	$82,688	$0	$0	$0	$0	$0	$0	$0	$0	$0	$106,875
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$163,261	$174,511	$187,448	$270,136	$270,136	$270,136	$270,136	$270,136	$270,136	$270,136	$270,136	$270,136	$270,136	
3. Less: Accumulated Depreciation	$51,420	$51,772	$52,139	$52,565	$53,044	$53,522	$54,000	$54,478	$54,957	$55,435	$55,913	$56,391	$56,870	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$10,125	$43,875	$82,688	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$121,966	$166,614	$217,997	$217,571	$217,092	$216,614	$216,136	$215,658	$215,179	$214,701	$214,223	$213,745	$213,266	
6. Average Net Investment		$144,290	$192,305	$217,784	$217,331	$216,853	$216,375	$215,897	$215,418	$214,940	$214,462	$213,984	$213,505	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$840	$1,119	$1,267	$1,265	$1,262	$1,259	$1,256	$1,254	$1,251	$1,248	$1,245	$1,242	$14,508
b. Debt Component (Line 6 x debt rate) (c) (f)		$143	$190	$215	$215	$214	$214	$213	$213	$212	$212	$211	$211	$2,464
8. Investment Expenses														
a. Depreciation (d)		$352	$367	$427	$478	$478	$478	$478	$478	$478	$478	$478	$478	$5,449
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$1,334	$1,676	$1,909	$1,958	$1,954	$1,951	$1,948	$1,945	$1,941	$1,938	$1,935	$1,932	$22,421

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
23 - SPCC - Spill Prevention, Control & Countermeasures														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		($559,968)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($559,968)
c. Retirements		($559,968)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($559,968)
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$695,796	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$695,796
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
h. Regulatory Assets		$695,796	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$695,796
2. Plant-In-Service/Depreciation Base (a)	$6,111,854	$5,551,886	$5,551,886	$5,551,886	$5,551,886	$5,551,886	$5,551,886	$5,551,886	$5,551,886	$5,551,886	$5,551,886	$5,551,886	$5,551,886	
3. Less: Accumulated Depreciation	$1,078,479	$1,227,735	$1,240,403	$1,253,070	$1,265,737	$1,278,405	$1,291,072	$1,303,739	$1,316,406	$1,329,074	$1,341,741	$1,354,408	$1,367,076	
a. Less: Capital Recovery Unamortized Balance	($633,708)	($1,317,678)	($1,304,258)	($1,290,838)	($1,277,418)	($1,263,998)	($1,250,578)	($1,237,159)	($1,223,739)	($1,210,319)	($1,196,899)	($1,183,479)	($1,170,059)	
4. CWIP	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	
5. Net Investment (Lines 2 - 3 + 4)	$5,667,082	$5,641,827	$5,615,740	$5,589,652	$5,563,565	$5,537,478	$5,511,391	$5,485,304	$5,459,217	$5,433,130	$5,407,043	$5,380,955	$5,354,868	
6. Average Net Investment		$5,654,455	$5,628,783	$5,602,696	$5,576,609	$5,550,522	$5,524,435	$5,498,347	$5,472,260	$5,446,173	$5,420,086	$5,393,999	$5,367,912	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$32,905	$32,756	$32,604	$32,452	$32,300	$32,148	$31,997	$31,845	$31,693	$31,541	$31,389	$31,238	$384,867
b. Debt Component (Line 6 x debt rate) (c) (f)		$5,588	$5,562	$5,537	$5,511	$5,485	$5,459	$5,433	$5,408	$5,382	$5,356	$5,330	$5,305	$65,356
8. Investment Expenses														
a. Depreciation (d)		$13,430	$12,667	$12,667	$12,667	$12,667	$12,667	$12,667	$12,667	$12,667	$12,667	$12,667	$12,667	$152,770
b. Amortization (e)		$11,826	$13,420	$13,420	$13,420	$13,420	$13,420	$13,420	$13,420	$13,420	$13,420	$13,420	$13,420	$159,444
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$63,748	$64,405	$64,227	$64,050	$63,872	$63,695	$63,517	$63,340	$63,162	$62,984	$62,807	$62,629	$762,437

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
23 - SPCC - Spill Prevention, Control & Countermeasures														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$101,750	$101,750	$101,750	$101,750	$101,750	$101,750	$0	$0	$0	$610,500
b. Clearings to Plant		($826,116)	$0	$0	$0	$0	$0	$0	$0	$711,000	$0	$0	$0	($115,116)
c. Retirements		($826,116)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($826,116)
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$754,953	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$754,953
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
h. Regulatory Assets		$754,953	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$754,953
2. Plant-In-Service/Depreciation Base (a)	$3,043,760	$2,217,644	$2,217,644	$2,217,644	$2,217,644	$2,217,644	$2,217,644	$2,217,644	$2,217,644	$2,928,644	$2,928,644	$2,928,644	$2,928,644	
3. Less: Accumulated Depreciation	$1,563,584	$1,502,823	$1,512,049	$1,521,274	$1,530,500	$1,539,725	$1,548,951	$1,558,177	$1,567,402	$1,577,425	$1,588,244	$1,599,064	$1,609,883	
a. Less: Capital Recovery Unamortized Balance	($785,045)	($1,526,048)	($1,509,777)	($1,493,506)	($1,477,235)	($1,460,964)	($1,444,693)	($1,428,422)	($1,412,152)	($1,395,881)	($1,379,610)	($1,363,339)	($1,347,068)	
4. CWIP	$100,500	$100,500	$100,500	$100,500	$202,250	$304,000	$405,750	$507,500	$609,250	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$2,365,721	$2,341,368	$2,315,872	$2,290,375	$2,366,629	$2,442,882	$2,519,136	$2,595,390	$2,671,643	$2,747,100	$2,720,010	$2,692,919	$2,665,829	
6. Average Net Investment		$2,353,545	$2,328,620	$2,303,124	$2,328,502	$2,404,756	$2,481,009	$2,557,263	$2,633,516	$2,709,372	$2,733,555	$2,706,464	$2,679,374	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$13,696	$13,551	$13,403	$13,550	$13,994	$14,438	$14,881	$15,325	$15,767	$15,907	$15,750	$15,592	$175,854
b. Debt Component (Line 6 x debt rate) (c) (f)		$2,326	$2,301	$2,276	$2,301	$2,376	$2,452	$2,527	$2,602	$2,677	$2,701	$2,675	$2,648	$29,863
8. Investment Expenses														
a. Depreciation (d)		$10,403	$9,226	$9,226	$9,226	$9,226	$9,226	$9,226	$9,226	$10,023	$10,819	$10,819	$10,819	$117,463
b. Amortization (e)		$13,950	$16,271	$16,271	$16,271	$16,271	$16,271	$16,271	$16,271	$16,271	$16,271	$16,271	$16,271	$192,929
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$40,375	$41,349	$41,175	$41,348	$41,867	$42,386	$42,905	$43,424	$44,737	$45,699	$45,515	$45,330	$516,109

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
23 - SPCC - Spill Prevention, Control & Countermeasures														
Transmission														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$4,120,752	$4,120,752	$4,120,752	$4,120,752	$4,120,752	$4,120,752	$4,120,752	$4,120,752	$4,120,752	$4,120,752	$4,120,752	$4,120,752	$4,120,752	
3. Less: Accumulated Depreciation	$605,266	$611,935	$618,605	$625,274	$631,944	$638,614	$645,283	$651,953	$658,622	$665,292	$671,961	$678,631	$685,300	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$3,515,486	$3,508,817	$3,502,147	$3,495,478	$3,488,808	$3,482,138	$3,475,469	$3,468,799	$3,462,130	$3,455,460	$3,448,791	$3,442,121	$3,435,452	
6. Average Net Investment		$3,512,151	$3,505,482	$3,498,812	$3,492,143	$3,485,473	$3,478,804	$3,472,134	$3,465,465	$3,458,795	$3,452,125	$3,445,456	$3,438,786	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$20,438	$20,399	$20,361	$20,322	$20,283	$20,244	$20,205	$20,167	$20,128	$20,089	$20,050	$20,011	$242,698
b. Debt Component (Line 6 x debt rate) (c) (f)		$3,471	$3,464	$3,458	$3,451	$3,444	$3,438	$3,431	$3,425	$3,418	$3,411	$3,405	$3,398	$41,213
8. Investment Expenses														
a. Depreciation (d)		$6,670	$6,670	$6,670	$6,670	$6,670	$6,670	$6,670	$6,670	$6,670	$6,670	$6,670	$6,670	$80,035
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$30,579	$30,533	$30,488	$30,442	$30,397	$30,352	$30,306	$30,261	$30,215	$30,170	$30,125	$30,079	$363,946

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
24 - Manatee Reburn														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		($31,863,719)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($31,863,719)
c. Retirements		($31,863,719)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($31,863,719)
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$15,778,027	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$15,778,027
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
h. Regulatory Assets		$15,778,027	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$15,778,027
2. Plant-In-Service/Depreciation Base (a)	$31,863,719	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3. Less: Accumulated Depreciation	$16,021,844	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
a. Less: Capital Recovery Unamortized Balance	$0	($15,778,027)	($15,712,285)	($15,646,543)	($15,580,801)	($15,515,060)	($15,449,318)	($15,383,576)	($15,317,834)	($15,252,092)	($15,186,351)	($15,120,609)	($15,054,867)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$15,841,875	$15,778,027	$15,712,285	$15,646,543	$15,580,801	$15,515,060	$15,449,318	$15,383,576	$15,317,834	$15,252,092	$15,186,351	$15,120,609	$15,054,867	
6. Average Net Investment		$15,809,951	$15,745,156	$15,679,414	$15,613,672	$15,547,930	$15,482,189	$15,416,447	$15,350,705	$15,284,963	$15,219,222	$15,153,480	$15,087,738	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$92,003	$91,626	$91,243	$90,861	$90,478	$90,096	$89,713	$89,330	$88,948	$88,565	$88,183	$87,800	$1,078,845
b. Debt Component (Line 6 x debt rate) (c) (f)		$15,623	$15,559	$15,494	$15,429	$15,364	$15,299	$15,235	$15,170	$15,105	$15,040	$14,975	$14,910	$183,203
8. Investment Expenses														
a. Depreciation (d)		$63,848	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$63,848
b. Amortization (e)		$0	$65,742	$65,742	$65,742	$65,742	$65,742	$65,742	$65,742	$65,742	$65,742	$65,742	$65,742	$723,160
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$171,474	$172,927	$172,479	$172,032	$171,584	$171,137	$170,689	$170,242	$169,794	$169,347	$168,899	$168,452	$2,049,056

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
26 - UST Remove/Replacement														
General														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	
3. Less: Accumulated Depreciation	$56,366	$56,511	$56,655	$56,799	$56,944	$57,088	$57,232	$57,377	$57,521	$57,665	$57,809	$57,954	$58,098	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$59,080	$58,936	$58,792	$58,647	$58,503	$58,359	$58,214	$58,070	$57,926	$57,782	$57,637	$57,493	$57,349	
6. Average Net Investment		$59,008	$58,864	$58,720	$58,575	$58,431	$58,287	$58,142	$57,998	$57,854	$57,709	$57,565	$57,421	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$343	$343	$342	$341	$340	$339	$338	$338	$337	$336	$335	$334	$4,065
b. Debt Component (Line 6 x debt rate) (c) (f)		$58	$58	$58	$58	$58	$58	$57	$57	$57	$57	$57	$57	$690
8. Investment Expenses														
a. Depreciation (d)		$144	$144	$144	$144	$144	$144	$144	$144	$144	$144	$144	$144	$1,732
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$546	$545	$544	$543	$542	$541	$540	$539	$538	$537	$536	$535	$6,487

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
27 - Lowest Quality Water Source														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$102,800	$102,800	$102,800	$102,800	$411,200
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$15,306,478	$15,306,478	$15,306,478	$15,306,478	$15,306,478	$15,306,478	$15,306,478	$15,306,478	$15,306,478	$15,306,478	$15,306,478	$15,306,478	$15,306,478	
3. Less: Accumulated Depreciation	$6,105,483	$6,156,505	$6,207,527	$6,258,548	$6,309,570	$6,360,591	$6,411,613	$6,462,635	$6,513,656	$6,564,678	$6,615,699	$6,666,721	$6,717,743	
a. Less: Capital Recovery Unamortized Balance	($3,344,683)	($3,344,683)	($3,344,683)	($3,344,683)	($3,344,683)	($3,344,683)	($3,344,683)	($3,344,683)	($3,344,683)	($3,344,683)	($3,344,683)	($3,344,683)	($3,344,683)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$102,800	$205,600	$308,400	$411,200	
5. Net Investment (Lines 2 - 3 + 4)	$12,545,678	$12,494,656	$12,443,635	$12,392,613	$12,341,591	$12,290,570	$12,239,548	$12,188,527	$12,137,505	$12,189,283	$12,241,062	$12,292,840	$12,344,618	
6. Average Net Investment		$12,520,167	$12,469,145	$12,418,124	$12,367,102	$12,316,081	$12,265,059	$12,214,037	$12,163,016	$12,163,394	$12,215,172	$12,266,951	$12,318,729	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$72,859	$72,562	$72,265	$71,968	$71,671	$71,374	$71,077	$70,780	$70,782	$71,084	$71,385	$71,686	$859,493
b. Debt Component (Line 6 x debt rate) (c) (f)		$12,372	$12,322	$12,272	$12,221	$12,171	$12,120	$12,070	$12,019	$12,020	$12,071	$12,122	$12,173	$145,954
8. Investment Expenses														
a. Depreciation (d)		$51,022	$51,022	$51,022	$51,022	$51,022	$51,022	$51,022	$51,022	$51,022	$51,022	$51,022	$51,022	$612,259
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$136,253	$135,905	$135,558	$135,211	$134,863	$134,516	$134,169	$133,821	$133,824	$134,176	$134,529	$134,881	$1,617,707

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
27 - Lowest Quality Water Source														
Intermediate														
1. Investments														
a. Expenditures/Additions		$1,941,464	$1,941,464	$2,195,839	$1,941,464	$1,941,464	$2,195,839	$1,941,464	$1,941,464	$2,348,464	$1,941,464	$3,467,714	$3,467,714	$27,265,814
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,442,000	$1,526,250	$3,968,250
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$21,590,761	$21,590,761	$21,590,761	$21,590,761	$21,590,761	$21,590,761	$21,590,761	$21,590,761	$21,590,761	$21,590,761	$21,590,761	$24,032,761	$25,559,011	
3. Less: Accumulated Depreciation	$4,451,800	$4,536,364	$4,620,928	$4,705,492	$4,790,055	$4,874,619	$4,959,183	$5,043,747	$5,128,311	$5,212,875	$5,297,438	$5,390,101	$5,495,926	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$1,993,136	$3,934,600	$5,876,063	$8,071,902	$10,013,366	$11,954,829	$14,150,668	$16,092,132	$18,033,595	$20,382,059	$22,323,523	$23,349,236	$25,290,700	
5. Net Investment (Lines 2 - 3 + 4)	$19,132,097	$20,988,997	$22,845,897	$24,957,172	$26,814,071	$28,670,971	$30,782,246	$32,639,146	$34,496,046	$36,759,946	$38,616,846	$41,991,896	$45,353,785	
6. Average Net Investment		$20,060,547	$21,917,447	$23,901,534	$25,885,621	$27,742,521	$29,726,609	$31,710,696	$33,567,596	$35,627,996	$37,688,396	$40,304,371	$43,672,841	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$116,738	$127,544	$139,090	$150,636	$161,442	$172,988	$184,534	$195,340	$207,330	$219,320	$234,543	$254,145	$2,163,652
b. Debt Component (Line 6 x debt rate) (c) (f)		$19,824	$21,659	$23,619	$25,580	$27,415	$29,376	$31,337	$33,171	$35,208	$37,244	$39,829	$43,158	$367,419
8. Investment Expenses														
a. Depreciation (d)		$84,564	$84,564	$84,564	$84,564	$84,564	$84,564	$84,564	$84,564	$84,564	$84,564	$92,663	$105,824	$1,044,126
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$221,126	$233,767	$247,274	$260,780	$273,421	$286,928	$300,434	$313,075	$327,101	$341,128	$367,035	$403,127	$3,575,197

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
28 - CWA 316(b) Phase II Rule														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$4,678,319	$4,678,319	$4,678,319	$4,678,319	$4,678,319	$4,678,319	$4,678,319	$4,678,319	$4,678,319	$4,678,319	$4,678,319	$4,678,319	$4,678,319	
3. Less: Accumulated Depreciation	$129,495	$146,526	$163,558	$180,589	$197,621	$214,652	$231,684	$248,715	$265,746	$282,778	$299,809	$316,841	$333,872	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$4,548,825	$4,531,793	$4,514,762	$4,497,730	$4,480,699	$4,463,667	$4,446,636	$4,429,604	$4,412,573	$4,395,541	$4,378,510	$4,361,478	$4,344,447	
6. Average Net Investment		$4,540,309	$4,523,277	$4,506,246	$4,489,214	$4,472,183	$4,455,151	$4,438,120	$4,421,089	$4,404,057	$4,387,026	$4,369,994	$4,352,963	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$26,421	$26,322	$26,223	$26,124	$26,025	$25,926	$25,827	$25,728	$25,629	$25,529	$25,430	$25,331	$310,516
b. Debt Component (Line 6 x debt rate) (c) (f)		$4,487	$4,470	$4,453	$4,436	$4,419	$4,403	$4,386	$4,369	$4,352	$4,335	$4,318	$4,302	$52,730
8. Investment Expenses														
a. Depreciation (d)		$17,031	$17,031	$17,031	$17,031	$17,031	$17,031	$17,031	$17,031	$17,031	$17,031	$17,031	$17,031	$204,378
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$47,940	$47,824	$47,708	$47,592	$47,476	$47,360	$47,244	$47,128	$47,012	$46,896	$46,780	$46,664	$567,623

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
34 - St Lucie Cooling Water System Inspection & Maintenance														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$8,743	$27,744	$33,941	$105,833	$479,474	$656,094	$689,933	$733,376	$2,735,138
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,735,138	$2,735,138
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,735,138	
3. Less: Accumulated Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,564	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$4,449,942	$4,449,942	$4,449,942	$4,449,942	$4,449,942	$4,458,685	$4,486,429	$4,520,370	$4,626,203	$5,105,677	$5,761,771	$6,451,704	$4,449,942	
5. Net Investment (Lines 2 - 3 + 4)	$4,449,942	$4,449,942	$4,449,942	$4,449,942	$4,449,942	$4,458,685	$4,486,429	$4,520,370	$4,626,203	$5,105,677	$5,761,771	$6,451,704	$7,182,516	
6. Average Net Investment		$4,449,942	$4,449,942	$4,449,942	$4,449,942	$4,454,314	$4,472,557	$4,503,400	$4,573,287	$4,865,940	$5,433,724	$6,106,738	$6,817,110	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$25,896	$25,896	$25,896	$25,896	$25,921	$26,027	$26,207	$26,613	$28,316	$31,620	$35,537	$39,671	$343,495
b. Debt Component (Line 6 x debt rate) (c) (f)		$4,397	$4,397	$4,397	$4,397	$4,402	$4,420	$4,450	$4,519	$4,809	$5,370	$6,035	$6,737	$58,330
8. Investment Expenses														
a. Depreciation (d)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,564	$2,564
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$30,293	$30,293	$30,293	$30,293	$30,323	$30,447	$30,657	$31,133	$33,125	$36,990	$41,572	$48,972	$404,389

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
35 - Martin Plant Drinking Water System Compliance														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$100,891	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$100,891
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
h. Regulatory Assets		$100,891	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$100,891
2. Plant-In-Service/Depreciation Base (a)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3. Less: Accumulated Depreciation	($100,891)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
a. Less: Capital Recovery Unamortized Balance	$0	($100,470)	($100,050)	($99,630)	($99,209)	($98,789)	($98,369)	($97,948)	($97,528)	($97,107)	($96,687)	($96,267)	($95,846)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$100,891	$100,470	$100,050	$99,630	$99,209	$98,789	$98,369	$97,948	$97,528	$97,107	$96,687	$96,267	$95,846	
6. Average Net Investment		$100,681	$100,260	$99,840	$99,419	$98,999	$98,579	$98,158	$97,738	$97,318	$96,897	$96,477	$96,056	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$586	$583	$581	$579	$576	$574	$571	$569	$566	$564	$561	$559	$6,869
b. Debt Component (Line 6 x debt rate) (c) (f)		$99	$99	$99	$98	$98	$97	$97	$97	$96	$96	$95	$95	$1,166
8. Investment Expenses														
a. Depreciation (d)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization (e)		$420	$420	$420	$420	$420	$420	$420	$420	$420	$420	$420	$420	$5,045
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$1,106	$1,103	$1,100	$1,097	$1,094	$1,091	$1,089	$1,086	$1,083	$1,080	$1,077	$1,074	$13,080

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.

(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.

(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.

(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.

(e) Applicable amortization period(s). See Depreciation Schedule 4P.

(f) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
35 - Martin Plant Drinking Water System Compliance														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$76,111	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$76,111
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
h. Regulatory Assets		$76,111	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$76,111
2. Plant-In-Service/Depreciation Base (a)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3. Less: Accumulated Depreciation	($76,111)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	
a. Less: Capital Recovery Unamortized Balance	$0	($75,793)	($75,476)	($75,159)	($74,842)	($74,525)	($74,208)	($73,891)	($73,574)	($73,256)	($72,939)	($72,622)	($72,305)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$76,111	$75,793	$75,476	$75,159	$74,842	$74,525	$74,208	$73,891	$73,574	$73,256	$72,939	$72,622	$72,305	
6. Average Net Investment		$75,952	$75,635	$75,318	$75,001	$74,684	$74,366	$74,049	$73,732	$73,415	$73,098	$72,781	$72,464	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$442	$440	$438	$436	$435	$433	$431	$429	$427	$425	$424	$422	$5,182
b. Debt Component (Line 6 x debt rate) (c) (f)		$75	$75	$74	$74	$74	$73	$73	$73	$73	$72	$72	$72	$880
8. Investment Expenses														
a. Depreciation (d)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization (e)		$317	$317	$317	$317	$317	$317	$317	$317	$317	$317	$317	$317	$3,806
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$834	$832	$830	$828	$826	$823	$821	$819	$817	$815	$813	$810	$9,868

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
36 - Low-Level Radioactive Waste Storage														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	
3. Less: Accumulated Depreciation	$3,461,559	$3,501,518	$3,541,476	$3,581,435	$3,621,394	$3,661,353	$3,701,312	$3,741,270	$3,781,229	$3,821,188	$3,861,147	$3,901,106	$3,941,064	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$13,995,245	$13,955,286	$13,915,327	$13,875,368	$13,835,410	$13,795,451	$13,755,492	$13,715,533	$13,675,574	$13,635,616	$13,595,657	$13,555,698	$13,515,739	
6. Average Net Investment		$13,975,265	$13,935,307	$13,895,348	$13,855,389	$13,815,430	$13,775,471	$13,735,513	$13,695,554	$13,655,595	$13,615,636	$13,575,677	$13,535,719	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$81,326	$81,094	$80,861	$80,629	$80,396	$80,164	$79,931	$79,699	$79,466	$79,234	$79,001	$78,768	$960,568
b. Debt Component (Line 6 x debt rate) (c) (f)		$13,810	$13,771	$13,731	$13,692	$13,652	$13,613	$13,573	$13,534	$13,494	$13,455	$13,415	$13,376	$163,118
8. Investment Expenses														
a. Depreciation (d)		$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$479,506
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$135,095	$134,823	$134,551	$134,279	$134,007	$133,735	$133,463	$133,191	$132,919	$132,647	$132,375	$132,103	$1,603,192

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
37 - DeSoto Next Generation Solar Energy Center														
Solar														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$10,175	$0	$5,088	$0	$0	$0	$0	$0	$15,263
b. Clearings to Plant		$0	($3,803)	($5,261)	$0	$0	$0	$15,263	$0	$0	$0	$0	$0	$6,199
c. Retirements		$0	($3,803)	($5,261)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($9,064)
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$153,627,320	$153,627,320	$153,623,518	$153,618,256	$153,618,256	$153,618,256	$153,618,256	$153,633,519	$153,633,519	$153,633,519	$153,633,519	$153,633,519	$153,633,519	
3. Less: Accumulated Depreciation	$62,667,591	$63,109,662	$63,547,909	$63,984,601	$64,426,481	$64,868,361	$65,310,242	$65,752,143	$66,194,066	$66,635,989	$67,077,912	$67,519,835	$67,961,758	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$10,175	$10,175	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$90,959,730	$90,517,658	$90,075,609	$89,633,656	$89,191,775	$88,760,070	$88,318,190	$87,881,376	$87,439,453	$86,997,530	$86,555,607	$86,113,684	$85,671,761	
6. Average Net Investment		$90,738,694	$90,296,633	$89,854,632	$89,412,715	$88,975,923	$88,539,130	$88,099,783	$87,660,414	$87,218,491	$86,776,568	$86,334,645	$85,892,722	
a. Average ITC Balance		$26,061,201	$25,939,135	$25,817,069	$25,695,003	$25,572,937	$25,450,871	$25,328,805	$25,206,739	$25,084,673	$24,962,607	$24,840,541	$24,718,475	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$562,850	$560,115	$557,380	$554,645	$551,940	$549,235	$546,515	$543,796	$541,061	$538,326	$535,591	$532,857	$6,574,311
b. Debt Component (Line 6 x debt rate) (c) (f)		$94,753	$94,292	$93,831	$93,371	$92,915	$92,460	$92,002	$91,544	$91,083	$90,623	$90,162	$89,702	$1,106,737
8. Investment Expenses														
a. Depreciation (d)		$432,988	$432,965	$432,869	$432,796	$432,796	$432,796	$432,818	$432,839	$432,839	$432,839	$432,839	$432,839	$5,194,223
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$9,084	$9,084	$9,084	$9,084	$9,084	$9,084	$9,084	$9,084	$9,084	$9,084	$9,084	$9,084	$109,008
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. ITC Solar		($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($1,924,740)
9. Total System Recoverable Expenses (Lines 7 + 8)		$939,280	$936,061	$932,769	$929,501	$926,341	$923,180	$920,024	$916,867	$913,672	$910,477	$907,282	$904,086	$11,059,540

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
38 - Space Coast Next Generation Solar Energy Center														
Solar														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$70,565,354	$70,565,354	$70,565,354	$70,565,354	$70,565,354	$70,565,354	$70,565,354	$70,565,354	$70,565,354	$70,565,354	$70,565,354	$70,565,354	$70,565,354	
3. Less: Accumulated Depreciation	$27,809,033	$28,006,084	$28,203,136	$28,400,188	$28,597,239	$28,794,291	$28,991,343	$29,188,394	$29,385,446	$29,582,498	$29,779,549	$29,976,601	$30,173,653	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$42,756,321	$42,559,270	$42,362,218	$42,165,167	$41,968,115	$41,771,063	$41,574,012	$41,376,960	$41,179,908	$40,982,857	$40,785,805	$40,588,753	$40,391,702	
6. Average Net Investment		$42,657,796	$42,460,744	$42,263,692	$42,066,641	$41,869,589	$41,672,537	$41,475,486	$41,278,434	$41,081,382	$40,884,331	$40,687,279	$40,490,227	
a. Average ITC Balance		$11,210,259	$11,159,070	$11,107,881	$11,056,692	$11,005,503	$10,954,314	$10,903,125	$10,851,936	$10,800,747	$10,749,558	$10,698,369	$10,647,180	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$263,214	$261,999	$260,784	$259,569	$258,354	$257,139	$255,924	$254,709	$253,493	$252,278	$251,063	$249,848	$3,078,374
b. Debt Component (Line 6 x debt rate) (c) (f)		$44,342	$44,137	$43,932	$43,727	$43,523	$43,318	$43,113	$42,909	$42,704	$42,499	$42,294	$42,090	$518,588
8. Investment Expenses														
a. Depreciation (d)		$194,957	$194,957	$194,957	$194,957	$194,957	$194,957	$194,957	$194,957	$194,957	$194,957	$194,957	$194,957	$2,339,490
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$2,094	$2,094	$2,094	$2,094	$2,094	$2,094	$2,094	$2,094	$2,094	$2,094	$2,094	$2,094	$25,130
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. ITC Solar		($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($807,156)
9. Total System Recoverable Expenses (Lines 7 + 8)		$437,344	$435,925	$434,505	$433,085	$431,665	$430,245	$428,826	$427,406	$425,986	$424,566	$423,146	$421,727	$5,154,426

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
39 - Martin Next Generation Solar Energy Center														
Intermediate														
1. Investments														
a. Expenditures/Additions		$210,171	$210,160	$214,500	$210,096	$210,114	$210,101	$210,102	$210,113	$210,110	$210,087	$210,068	$210,049	$2,525,671
b. Clearings to Plant		$717,847	$0	$0	$0	$0	$0	$0	($6,412)	($11,214)	($9,863)	($10,872)	($17,435)	$662,052
c. Retirements		$0	$0	$0	$0	$0	$0	$0	($6,412)	($11,214)	($9,863)	($10,872)	($17,435)	($55,795)
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$427,975,986	$428,693,833	$428,693,833	$428,693,833	$428,693,833	$428,693,833	$428,693,833	$428,693,833	$428,687,421	$428,676,207	$428,666,344	$428,655,473	$428,638,037	
3. Less: Accumulated Depreciation	$136,528,913	$137,606,029	$138,684,007	$139,761,984	$140,839,962	$141,917,940	$142,995,917	$144,073,895	$145,145,422	$146,212,043	$147,279,890	$148,346,604	$149,406,586	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$717,847	$210,171	$420,331	$634,831	$844,927	$1,055,041	$1,265,142	$1,475,244	$1,685,357	$1,895,467	$2,105,554	$2,315,622	$2,525,671	
5. Net Investment (Lines 2 - 3 + 4)	$292,164,920	$291,297,975	$290,430,157	$289,566,679	$288,698,798	$287,830,934	$286,963,057	$286,095,182	$285,227,355	$284,359,631	$283,492,008	$282,624,491	$281,757,123	
6. Average Net Investment		$291,731,447	$290,864,066	$289,998,418	$289,132,739	$288,264,866	$287,396,996	$286,529,120	$285,661,268	$284,793,493	$283,925,820	$283,058,250	$282,190,807	
a. Average ITC Balance		$77,970,049	$77,626,251	$77,282,453	$76,938,655	$76,594,857	$76,251,059	$75,907,261	$75,563,463	$75,219,665	$74,875,867	$74,532,069	$74,188,271	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$1,801,832	$1,796,325	$1,790,828	$1,785,331	$1,779,822	$1,774,312	$1,768,802	$1,763,293	$1,757,784	$1,752,275	$1,746,767	$1,741,260	$21,258,632
b. Debt Component (Line 6 x debt rate) (c) (f)		$303,501	$302,577	$301,654	$300,732	$299,807	$298,882	$297,958	$297,033	$296,108	$295,184	$294,259	$293,335	$3,581,030
8. Investment Expenses														
a. Depreciation (d)		$1,031,559	$1,032,421	$1,032,421	$1,032,421	$1,032,421	$1,032,421	$1,032,421	$1,032,382	$1,032,277	$1,032,152	$1,032,029	$1,031,860	$12,386,783
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$45,557	$45,557	$45,557	$45,557	$45,557	$45,557	$45,557	$45,557	$45,557	$45,557	$45,557	$45,557	$546,685
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. ITC Solar		($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($5,421,012)
9. Total System Recoverable Expenses (Lines 7 + 8)		$2,730,698	$2,725,129	$2,718,709	$2,712,290	$2,705,855	$2,699,421	$2,692,987	$2,686,514	$2,679,976	$2,673,417	$2,666,861	$2,660,261	$32,352,118

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.

(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.

(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.

(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.

(e) Applicable amortization period(s). See Depreciation Schedule 4P.

(f) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
41 - Manatee Temporary Heating System														
Distribution														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$1,416,860	$1,416,860	$1,416,860	$1,416,860	$1,416,860	$1,416,860	$1,416,860	$1,416,860	$1,416,860	$1,416,860	$1,416,860	$1,416,860	$1,416,860	
3. Less: Accumulated Depreciation	$1,189,155	$1,189,155	$1,189,155	$1,189,155	$1,189,155	$1,189,155	$1,189,155	$1,189,155	$1,189,155	$1,189,155	$1,189,155	$1,189,155	$1,189,155	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	
6. Average Net Investment		$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$1,325	$1,325	$1,325	$1,325	$1,325	$1,325	$1,325	$1,325	$1,325	$1,325	$1,325	$1,325	$15,901
b. Debt Component (Line 6 x debt rate) (c) (f)		$225	$225	$225	$225	$225	$225	$225	$225	$225	$225	$225	$225	$2,700
8. Investment Expenses														
a. Depreciation (d)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$1,550	$1,550	$1,550	$1,550	$1,550	$1,550	$1,550	$1,550	$1,550	$1,550	$1,550	$1,550	$18,601

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
41 - Manatee Temporary Heating System														
Transmission														
1. Investments														
a. Expenditures/Additions (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	
3. Less: Accumulated Depreciation	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	$276,404	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
6. Average Net Investment		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Debt Component (Line 6 x debt rate) (c)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8. Investment Expenses														
a. Depreciation (d)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.

(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.

(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.

(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.

(e) Applicable amortization period(s). See Depreciation Schedule 4P.

(f) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
41 - Manatee Temporary Heating System														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$17,576,282	$17,576,282	$17,576,282	$17,576,282	$17,576,282	$17,576,282	$17,576,282	$17,576,282	$17,576,282	$17,576,282	$17,576,282	$17,576,282	$17,576,282	
3. Less: Accumulated Depreciation	$9,009,743	$9,206,134	$9,402,524	$9,598,914	$9,795,304	$9,991,695	$10,188,085	$10,384,475	$10,580,866	$10,777,256	$10,973,646	$11,170,036	$11,366,427	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$8,566,539	$8,370,149	$8,173,759	$7,977,368	$7,780,978	$7,584,588	$7,388,197	$7,191,807	$6,995,417	$6,799,027	$6,602,636	$6,406,246	$6,209,856	
6. Average Net Investment		$8,468,344	$8,271,954	$8,075,563	$7,879,173	$7,682,783	$7,486,393	$7,290,002	$7,093,612	$6,897,222	$6,700,832	$6,504,441	$6,308,051	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$49,280	$48,137	$46,994	$45,851	$44,708	$43,566	$42,423	$41,280	$40,137	$38,994	$37,851	$36,708	$515,930
b. Debt Component (Line 6 x debt rate) (c) (f)		$8,368	$8,174	$7,980	$7,786	$7,592	$7,398	$7,204	$7,010	$6,816	$6,622	$6,428	$6,234	$87,612
8. Investment Expenses														
a. Depreciation (d)		$196,390	$196,390	$196,390	$196,390	$196,390	$196,390	$196,390	$196,390	$196,390	$196,390	$196,390	$196,390	$2,356,683
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$254,039	$252,702	$251,365	$250,028	$248,691	$247,354	$246,017	$244,680	$243,343	$242,006	$240,669	$239,332	$2,960,225

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
42 - Turkey Point Cooling Canal Monitoring Plan														
Base														
1. Investments														
a. Expenditures/Additions		$93,459	$93,625	$114,902	$114,902	$126,072	$275,350	$219,157	$764,368	$150,000	$0	$0	$2,929,916	$4,881,751
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$710,000	$0	$0	$0	$5,276,346	$5,986,346
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$69,203,854	$69,203,854	$69,203,854	$69,203,854	$69,203,854	$69,203,854	$69,203,854	$69,203,854	$69,913,854	$69,913,854	$69,913,854	$69,913,854	$75,190,200	
3. Less: Accumulated Depreciation	$7,023,348	$7,211,981	$7,400,614	$7,589,247	$7,777,880	$7,966,513	$8,155,146	$8,343,778	$8,533,337	$8,723,822	$8,914,307	$9,104,792	$9,302,158	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$1,350,091	$1,443,550	$1,537,175	$1,652,077	$1,766,979	$1,893,051	$2,168,401	$2,387,558	$2,441,926	$2,591,926	$2,591,926	$2,591,926	$245,496	
5. Net Investment (Lines 2 - 3 + 4)	$63,530,598	$63,435,424	$63,340,416	$63,266,685	$63,192,954	$63,130,393	$63,217,110	$63,247,634	$63,822,443	$63,781,959	$63,591,474	$63,400,989	$66,133,539	
6. Average Net Investment		$63,483,011	$63,387,920	$63,303,550	$63,229,819	$63,161,674	$63,173,752	$63,232,372	$63,535,039	$63,802,201	$63,686,716	$63,496,231	$64,767,264	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$369,427	$368,873	$368,382	$367,953	$367,557	$367,627	$367,968	$369,730	$371,284	$370,612	$369,504	$376,900	$4,435,819
b. Debt Component (Line 6 x debt rate) (c) (f)		$62,734	$62,640	$62,557	$62,484	$62,416	$62,428	$62,486	$62,785	$63,049	$62,935	$62,747	$64,003	$753,265
8. Investment Expenses														
a. Depreciation (d)		$188,633	$188,633	$188,633	$188,633	$188,633	$188,633	$188,633	$189,559	$190,485	$190,485	$190,485	$197,366	$2,278,810
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$620,794	$620,146	$619,572	$619,070	$618,606	$618,688	$619,087	$622,074	$624,818	$624,032	$622,736	$638,269	$7,467,893

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
44 - Martin Plant Barley Barber Swamp Iron Mitigation														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	
3. Less: Accumulated Depreciation	$22,725	$22,923	$23,120	$23,317	$23,514	$23,711	$23,908	$24,106	$24,303	$24,500	$24,697	$24,894	$25,091	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$71,164	$70,967	$70,770	$70,573	$70,376	$70,178	$69,981	$69,784	$69,587	$69,390	$69,193	$68,995	$68,798	
6. Average Net Investment		$71,066	$70,868	$70,671	$70,474	$70,277	$70,080	$69,883	$69,685	$69,488	$69,291	$69,094	$68,897	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$414	$412	$411	$410	$409	$408	$407	$406	$404	$403	$402	$401	$4,887
b. Debt Component (Line 6 x debt rate) (c) (f)		$70	$70	$70	$70	$69	$69	$69	$69	$69	$68	$68	$68	$830
8. Investment Expenses														
a. Depreciation (d)		$197	$197	$197	$197	$197	$197	$197	$197	$197	$197	$197	$197	$2,366
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$681	$680	$678	$677	$676	$674	$673	$672	$670	$669	$668	$666	$8,083

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.

(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.

(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.

(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.

(e) Applicable amortization period(s). See Depreciation Schedule 4P.

(f) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
44 - Martin Plant Barley Barber Swamp Iron Mitigation														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	
3. Less: Accumulated Depreciation	$17,144	$17,292	$17,441	$17,590	$17,739	$17,887	$18,036	$18,185	$18,334	$18,482	$18,631	$18,780	$18,929	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$53,685	$53,537	$53,388	$53,239	$53,090	$52,942	$52,793	$52,644	$52,495	$52,347	$52,198	$52,049	$51,900	
6. Average Net Investment		$53,611	$53,462	$53,313	$53,165	$53,016	$52,867	$52,718	$52,570	$52,421	$52,272	$52,124	$51,975	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$312	$311	$310	$309	$309	$308	$307	$306	$305	$304	$303	$302	$3,687
b. Debt Component (Line 6 x debt rate) (c) (f)		$53	$53	$53	$53	$52	$52	$52	$52	$52	$52	$52	$51	$626
8. Investment Expenses														
a. Depreciation (d)		$149	$149	$149	$149	$149	$149	$149	$149	$149	$149	$149	$149	$1,785
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$514	$513	$512	$511	$510	$509	$508	$507	$506	$505	$504	$503	$6,098

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
47 - NPDES Permit Renewal Requirements														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$3,036,271	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,036,271
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$13,265,846	$13,265,846	$16,302,117	$16,302,117	$16,302,117	$16,302,117	$16,302,117	$16,302,117	$16,302,117	$16,302,117	$16,302,117	$16,302,117	$16,302,117	
3. Less: Accumulated Depreciation	$3,897,397	$3,949,133	$4,003,716	$4,061,145	$4,118,574	$4,176,003	$4,233,432	$4,290,861	$4,348,290	$4,405,719	$4,463,148	$4,520,577	$4,578,006	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$3,036,271	$3,036,271	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$12,404,719	$12,352,983	$12,298,401	$12,240,972	$12,183,543	$12,126,114	$12,068,685	$12,011,256	$11,953,826	$11,896,397	$11,838,968	$11,781,539	$11,724,110	
6. Average Net Investment		$12,378,851	$12,325,692	$12,269,686	$12,212,257	$12,154,828	$12,097,399	$12,039,970	$11,982,541	$11,925,112	$11,867,683	$11,810,254	$11,752,825	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$72,036	$71,727	$71,401	$71,067	$70,733	$70,398	$70,064	$69,730	$69,396	$69,062	$68,727	$68,393	$842,734
b. Debt Component (Line 6 x debt rate) (c) (f)		$12,233	$12,180	$12,125	$12,068	$12,011	$11,955	$11,898	$11,841	$11,784	$11,728	$11,671	$11,614	$143,108
8. Investment Expenses														
a. Depreciation (d)		$51,736	$54,583	$57,429	$57,429	$57,429	$57,429	$57,429	$57,429	$57,429	$57,429	$57,429	$57,429	$680,609
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$136,005	$138,490	$140,955	$140,564	$140,173	$139,782	$139,391	$139,000	$138,609	$138,218	$137,827	$137,436	$1,666,452

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
47 - NPDES Permit Renewal Requirements														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$3,798,266	$3,798,266	$3,798,266	$3,798,266	$3,798,266	$3,798,266	$3,798,266	$3,798,266	$3,798,266	$3,798,266	$3,798,266	$3,798,266	$3,798,266	
3. Less: Accumulated Depreciation	$581,034	$595,911	$610,787	$625,664	$640,540	$655,417	$670,293	$685,170	$700,046	$714,923	$729,799	$744,676	$759,553	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$3,217,232	$3,202,356	$3,187,479	$3,172,603	$3,157,726	$3,142,849	$3,127,973	$3,113,096	$3,098,220	$3,083,343	$3,068,467	$3,053,590	$3,038,714	
6. Average Net Investment		$3,209,794	$3,194,917	$3,180,041	$3,165,164	$3,150,288	$3,135,411	$3,120,535	$3,105,658	$3,090,782	$3,075,905	$3,061,028	$3,046,152	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$18,679	$18,592	$18,506	$18,419	$18,332	$18,246	$18,159	$18,073	$17,986	$17,900	$17,813	$17,726	$218,431
b. Debt Component (Line 6 x debt rate) (c) (f)		$3,172	$3,157	$3,143	$3,128	$3,113	$3,098	$3,084	$3,069	$3,054	$3,040	$3,025	$3,010	$37,093
8. Investment Expenses														
a. Depreciation (d)		$14,877	$14,877	$14,877	$14,877	$14,877	$14,877	$14,877	$14,877	$14,877	$14,877	$14,877	$14,877	$178,518
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$36,727	$36,626	$36,525	$36,423	$36,322	$36,221	$36,120	$36,018	$35,917	$35,816	$35,714	$35,613	$434,043

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
50 - Steam Electric Effluent Guidelines Revised Rules														
Base														
1. Investments														
a. Expenditures/Additions		($1,155,091)	$24,740	$24,740	$24,740	$24,740	$24,740	$24,740	$24,740	$24,740	$24,740	$24,740	$24,740	($882,955)
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$6,043,033	$6,043,033	$6,043,033	$6,043,033	$6,043,033	$6,043,033	$6,043,033	$6,043,033	$6,043,033	$6,043,033	$6,043,033	$6,043,033	$6,043,033	
3. Less: Accumulated Depreciation	$884,819	$904,385	$923,950	$943,516	$963,082	$982,647	$1,002,213	$1,021,779	$1,041,345	$1,060,910	$1,080,476	$1,100,042	$1,119,607	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$2,308,819	$1,153,729	$1,178,468	$1,203,208	$1,227,947	$1,252,687	$1,277,426	$1,302,166	$1,326,906	$1,351,645	$1,376,385	$1,401,124	$1,425,864	
5. Net Investment (Lines 2 - 3 + 4)	$7,467,033	$6,292,377	$6,297,550	$6,302,724	$6,307,898	$6,313,072	$6,318,246	$6,323,420	$6,328,594	$6,333,768	$6,338,941	$6,344,115	$6,349,289	
6. Average Net Investment		$6,879,705	$6,294,964	$6,300,137	$6,305,311	$6,310,485	$6,315,659	$6,320,833	$6,326,007	$6,331,181	$6,336,354	$6,341,528	$6,346,702	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$40,035	$36,632	$36,662	$36,693	$36,723	$36,753	$36,783	$36,813	$36,843	$36,873	$36,903	$36,933	$444,646
b. Debt Component (Line 6 x debt rate) (c) (f)		$6,799	$6,221	$6,226	$6,231	$6,236	$6,241	$6,246	$6,251	$6,256	$6,262	$6,267	$6,272	$75,507
8. Investment Expenses														
a. Depreciation (d)		$19,566	$19,566	$19,566	$19,566	$19,566	$19,566	$19,566	$19,566	$19,566	$19,566	$19,566	$19,566	$234,789
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$66,399	$62,419	$62,454	$62,489	$62,524	$62,560	$62,595	$62,630	$62,665	$62,700	$62,736	$62,771	$754,942

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
54 - Coal Combustion Residuals														
Base														
1. Investments														
a. Expenditures/Additions		$291,354	$1,067,529	$1,067,529	$1,067,529	$1,067,529	$1,067,529	$1,067,529	$1,067,529	$1,067,529	$1,067,529	$1,067,529	$1,843,704	$12,810,349
b. Clearings to Plant		($112,097,087)	$0	$0	$0	$0	$0	$0	$0	$14,476,964	$442,557	$442,557	$4,752,204	($91,982,805)
c. Retirements		($112,097,087)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($112,097,087)
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$105,232,017	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$105,232,017
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
h. Regulatory Assets		$106,470,289	$1,251,571	$917,695	$723,124	$666,267	$519,083	$36,852	$24,102	$0	$0	$0	$0	$110,608,984
2. Plant-In-Service/Depreciation Base (a)	$166,042,622	$53,945,536	$53,945,536	$53,945,536	$53,945,536	$53,945,536	$53,945,536	$53,945,536	$53,945,536	$68,422,500	$68,865,057	$69,307,614	$74,059,818	
3. Less: Accumulated Depreciation	$39,522,639	$33,813,340	$34,842,584	$35,871,827	$36,901,071	$37,930,315	$38,959,558	$39,988,802	$41,018,045	$42,065,385	$43,131,375	$44,198,470	$45,272,059	
a. Less: Capital Recovery Unamortized Balance	($35,983,902)	($142,391,203)	($143,139,245)	($143,551,602)	($143,768,021)	($143,926,425)	($143,936,658)	($143,464,197)	($142,978,935)	($142,469,550)	($141,960,165)	($141,450,781)	($140,941,396)	
4. CWIP	$33,097,334	$33,388,688	$34,456,217	$35,523,746	$36,591,275	$37,658,804	$38,726,334	$39,793,863	$40,861,392	$27,451,957	$28,076,929	$28,701,901	$25,793,401	
5. Net Investment (Lines 2 - 3 + 4)	$195,601,219	$195,912,087	$196,698,415	$197,149,057	$197,403,762	$197,600,451	$197,648,969	$197,214,793	$196,767,817	$196,278,621	$195,770,777	$195,261,825	$195,522,556	
6. Average Net Investment		$195,756,653	$196,305,251	$196,923,736	$197,276,410	$197,502,107	$197,624,710	$197,431,881	$196,991,305	$196,523,219	$196,024,699	$195,516,301	$195,392,191	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$1,139,167	$1,142,360	$1,145,959	$1,148,011	$1,149,324	$1,150,038	$1,148,916	$1,146,352	$1,143,628	$1,140,727	$1,137,768	$1,137,046	$13,729,296
b. Debt Component (Line 6 x debt rate) (c) (f)		$193,447	$193,989	$194,600	$194,949	$195,172	$195,293	$195,102	$194,667	$194,204	$193,712	$193,209	$193,087	$2,331,429
8. Investment Expenses														
a. Depreciation (d)		$292,880	$166,353	$166,353	$166,353	$166,353	$166,353	$166,353	$166,353	$184,449	$203,098	$204,205	$210,698	$2,259,800
b. Amortization (e)		$62,988	$503,530	$505,337	$506,705	$507,863	$508,850	$509,314	$509,365	$509,385	$509,385	$509,385	$509,385	$5,651,490
c. Dismantlement		$862,891	$862,891	$862,891	$862,891	$862,891	$862,891	$862,891	$862,891	$862,891	$862,891	$862,891	$862,891	$10,354,689
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$2,551,372	$2,869,122	$2,875,140	$2,878,908	$2,881,602	$2,883,425	$2,882,575	$2,879,627	$2,894,557	$2,909,812	$2,907,458	$2,913,106	$34,326,705

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
54 - Coal Combustion Residuals														
Intermediate														
1. Investments														
a. Expenditures/Additions		$751,844	$746,220	$2,262,000	$1,778,567	$1,587,220	$1,478,451	$1,471,113	$1,784,569	$1,173,195	$828,276	$395,542	$286,573	$14,543,570
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$12,116,753	$1,784,569	$1,173,195	$85,639,718	$395,542	$286,573	$101,396,351
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
h. Regulatory Assets		$217,190	$212,492	$307,128	$212,567	$214,941	$214,916	$217,258	$219,617	$217,273	$212,550	$217,191	$217,154	$2,680,279
2. Plant-In-Service/Depreciation Base (a)	$2,634,177	$2,634,177	$2,634,177	$2,634,177	$2,634,177	$2,634,177	$2,634,177	$14,750,930	$16,535,499	$17,708,694	$103,348,413	$103,743,955	$104,030,528	
3. Less: Accumulated Depreciation	$270,722	$281,039	$291,356	$301,674	$311,991	$322,308	$332,625	$366,671	$427,940	$495,002	$732,072	$1,137,628	$1,544,519	
a. Less: Capital Recovery Unamortized Balance	($15,531,377)	($15,717,352)	($15,898,271)	($16,173,393)	($16,353,521)	($16,535,666)	($16,717,429)	($16,901,172)	($17,086,912)	($17,269,942)	($17,447,893)	($17,630,125)	($17,811,959)	
4. CWIP	$86,852,780	$87,604,624	$88,350,844	$90,612,844	$92,391,411	$93,978,631	$95,457,082	$84,811,442	$84,811,442	$84,811,442	($0)	($0)	($0)	
5. Net Investment (Lines 2 - 3 + 4)	$104,747,612	$105,675,114	$106,591,936	$109,118,740	$111,067,118	$112,826,166	$114,476,062	$116,096,873	$118,005,912	$119,295,077	$120,064,233	$120,236,452	$120,297,967	
6. Average Net Investment		$105,211,363	$106,133,525	$107,855,338	$110,092,929	$111,946,642	$113,651,114	$115,286,467	$117,051,393	$118,650,495	$119,679,655	$120,150,342	$120,267,209	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$612,257	$617,623	$627,643	$640,664	$651,451	$661,370	$670,887	$681,157	$690,463	$696,452	$699,191	$699,871	$7,949,030
b. Debt Component (Line 6 x debt rate) (c) (f)		$103,970	$104,881	$106,583	$108,794	$110,626	$112,310	$113,926	$115,670	$117,250	$118,267	$118,733	$118,848	$1,349,858
8. Investment Expenses														
a. Depreciation (d)		$10,317	$10,317	$10,317	$10,317	$10,317	$10,317	$34,046	$61,269	$67,062	$237,070	$405,556	$406,892	$1,273,797
b. Amortization (e)		$31,215	$31,573	$32,006	$32,439	$32,796	$33,154	$33,514	$33,878	$34,242	$34,600	$34,958	$35,320	$399,697
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$757,759	$764,395	$776,549	$792,214	$805,190	$817,151	$852,373	$891,975	$909,017	$1,086,390	$1,258,438	$1,260,931	$10,972,382

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
123 - The Protected Species Project														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$1,689,831	$0	$0	$724,214	$0	$0	$0	$0	$152,625	$0	$2,566,670
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,616,738	$0	$0	$2,616,738
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$125,703	$125,703	$125,703	$125,703	$125,703	$125,703	$125,703	$125,703	$125,703	$125,703	$2,742,441	$2,742,441	$2,742,441	
3. Less: Accumulated Depreciation	$3,566	$3,876	$4,186	$4,496	$4,806	$5,116	$5,426	$5,736	$6,046	$6,356	$9,218	$14,631	$20,043	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$202,693	$202,693	$202,693	$1,892,524	$1,892,524	$1,892,524	$2,616,738	$2,616,738	$2,616,738	$2,616,738	$0	$152,625	$152,625	
5. Net Investment (Lines 2 - 3 + 4)	$324,830	$324,520	$324,210	$2,013,731	$2,013,421	$2,013,111	$2,737,015	$2,736,705	$2,736,395	$2,736,085	$2,733,223	$2,880,435	$2,875,023	
6. Average Net Investment		$324,675	$324,365	$1,168,971	$2,013,576	$2,013,266	$2,375,063	$2,736,860	$2,736,550	$2,736,240	$2,734,654	$2,806,829	$2,877,729	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$1,889	$1,888	$6,803	$11,718	$11,716	$13,821	$15,927	$15,925	$15,923	$15,914	$16,334	$16,746	$144,603
b. Debt Component (Line 6 x debt rate) (c) (f)		$321	$321	$1,155	$1,990	$1,990	$2,347	$2,705	$2,704	$2,704	$2,702	$2,774	$2,844	$24,556
8. Investment Expenses														
a. Depreciation (d)		$310	$310	$310	$310	$310	$310	$310	$310	$310	$2,861	$5,413	$5,413	$16,477
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$2,520	$2,518	$8,268	$14,017	$14,015	$16,478	$18,941	$18,939	$18,937	$21,478	$24,520	$25,003	$185,636

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
124 - FPL Miami-Dade Clean Water Recovery Center														
Intermediate														
1. Investments														
a. Expenditures/Additions		$772,000	$757,000	$2,550,000	$1,235,000	$1,260,000	$1,230,000	$1,230,000	$1,255,000	$4,280,000	$4,580,000	$5,555,000	$5,555,000	$30,259,000
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3. Less: Accumulated Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$2,644,000	$3,416,000	$4,173,000	$6,723,000	$7,958,000	$9,218,000	$10,448,000	$11,678,000	$12,933,000	$17,213,000	$21,793,000	$27,348,000	$32,903,000	
5. Net Investment (Lines 2 - 3 + 4)	$2,644,000	$3,416,000	$4,173,000	$6,723,000	$7,958,000	$9,218,000	$10,448,000	$11,678,000	$12,933,000	$17,213,000	$21,793,000	$27,348,000	$32,903,000	
6. Average Net Investment		$3,030,000	$3,794,500	$5,448,000	$7,340,500	$8,588,000	$9,833,000	$11,063,000	$12,305,500	$15,073,000	$19,503,000	$24,570,500	$30,125,500	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$17,632	$22,081	$31,704	$42,717	$49,976	$57,221	$64,379	$71,609	$87,714	$113,494	$142,983	$175,309	$876,820
b. Debt Component (Line 6 x debt rate) (c) (f)		$2,994	$3,750	$5,384	$7,254	$8,487	$9,717	$10,932	$12,160	$14,895	$19,273	$24,281	$29,770	$148,897
8. Investment Expenses														
a. Depreciation (d)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$20,627	$25,831	$37,087	$49,970	$58,463	$66,938	$75,311	$83,770	$102,609	$132,767	$167,264	$205,079	$1,025,717

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.

(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.

(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.

(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.

(e) Applicable amortization period(s). See Depreciation Schedule 4P.

(f) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
401 - Air Quality Assurance Testing														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$83,954	$83,954	$83,954	$83,954	$83,954	$83,954	$83,954	$83,954	$83,954	$83,954	$83,954	$83,954	$83,954	
3. Less: Accumulated Depreciation	$27,985	$28,984	$29,984	$30,983	$31,982	$32,982	$33,981	$34,981	$35,980	$36,980	$37,979	$38,979	$39,978	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$55,969	$54,970	$53,970	$52,971	$51,972	$50,972	$49,973	$48,973	$47,974	$46,974	$45,975	$44,975	$43,976	
6. Average Net Investment		$55,470	$54,470	$53,471	$52,471	$51,472	$50,472	$49,473	$48,473	$47,474	$46,475	$45,475	$44,476	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$323	$317	$311	$305	$300	$294	$288	$282	$276	$270	$265	$259	$3,490
b. Debt Component (Line 6 x debt rate) (c) (f)		$55	$54	$53	$52	$51	$50	$49	$48	$47	$46	$45	$44	$593
8. Investment Expenses														
a. Depreciation (d)		$999	$999	$999	$999	$999	$999	$999	$999	$999	$999	$999	$999	$11,993
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$1,377	$1,370	$1,363	$1,357	$1,350	$1,343	$1,336	$1,329	$1,323	$1,316	$1,309	$1,302	$16,076

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
402 - Crist 5, 6 & 7 Precipitator Projects														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$8,538,323	$8,538,323	$8,538,323	$8,538,323	$8,538,323	$8,538,323	$8,538,323	$8,538,323	$8,538,323	$8,538,323	$8,538,323	$8,538,323	$8,538,323	
3. Less: Accumulated Depreciation	($2,798,350)	($2,769,889)	($2,741,428)	($2,712,967)	($2,684,506)	($2,656,045)	($2,627,584)	($2,599,123)	($2,570,662)	($2,542,201)	($2,513,740)	($2,485,279)	($2,456,817)	
a. Less: Capital Recovery Unamortized Balance	($21,928,145)	($21,928,145)	($21,928,145)	($21,928,145)	($21,928,145)	($21,928,145)	($21,928,145)	($21,928,145)	($21,928,145)	($21,928,145)	($21,928,145)	($21,928,145)	($21,928,145)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$33,264,819	$33,236,358	$33,207,897	$33,179,435	$33,150,974	$33,122,513	$33,094,052	$33,065,591	$33,037,130	$33,008,669	$32,980,208	$32,951,747	$32,923,286	
6. Average Net Investment		$33,250,588	$33,222,127	$33,193,666	$33,165,205	$33,136,744	$33,108,283	$33,079,822	$33,051,361	$33,022,900	$32,994,439	$32,965,977	$32,937,516	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$193,495	$193,330	$193,164	$192,998	$192,833	$192,667	$192,501	$192,336	$192,170	$192,005	$191,839	$191,673	$2,311,011
b. Debt Component (Line 6 x debt rate) (c) (f)		$32,858	$32,830	$32,802	$32,774	$32,746	$32,718	$32,689	$32,661	$32,633	$32,605	$32,577	$32,549	$392,443
8. Investment Expenses														
a. Depreciation (d)		$28,461	$28,461	$28,461	$28,461	$28,461	$28,461	$28,461	$28,461	$28,461	$28,461	$28,461	$28,461	$341,533
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$254,815	$254,621	$254,427	$254,233	$254,040	$253,846	$253,652	$253,458	$253,265	$253,071	$252,877	$252,683	$3,044,987

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
403 - Crist 7 Flue Gas Conditioning														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3. Less: Accumulated Depreciation	($1,499,322)	($1,499,322)	($1,499,322)	($1,499,322)	($1,499,322)	($1,499,322)	($1,499,322)	($1,499,322)	($1,499,322)	($1,499,322)	($1,499,322)	($1,499,322)	($1,499,322)	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,499,322	$1,499,322	$1,499,322	$1,499,322	$1,499,322	$1,499,322	$1,499,322	$1,499,322	$1,499,322	$1,499,322	$1,499,322	$1,499,322	$1,499,322	
6. Average Net Investment		$1,499,322	$1,499,322	$1,499,322	$1,499,322	$1,499,322	$1,499,322	$1,499,322	$1,499,322	$1,499,322	$1,499,322	$1,499,322	$1,499,322	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$8,725	$8,725	$8,725	$8,725	$8,725	$8,725	$8,725	$8,725	$8,725	$8,725	$8,725	$8,725	$104,700
b. Debt Component (Line 6 x debt rate) (c) (f)		$1,482	$1,482	$1,482	$1,482	$1,482	$1,482	$1,482	$1,482	$1,482	$1,482	$1,482	$1,482	$17,780
8. Investment Expenses														
a. Depreciation (d)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$10,207	$10,207	$10,207	$10,207	$10,207	$10,207	$10,207	$10,207	$10,207	$10,207	$10,207	$10,207	$122,480

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
408 - Crist Cooling Tower Cell														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3. Less: Accumulated Depreciation	($531,926)	($531,926)	($531,926)	($531,926)	($531,926)	($531,926)	($531,926)	($531,926)	($531,926)	($531,926)	($531,926)	($531,926)	($531,926)	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$531,926	$531,926	$531,926	$531,926	$531,926	$531,926	$531,926	$531,926	$531,926	$531,926	$531,926	$531,926	$531,926	
6. Average Net Investment		$531,926	$531,926	$531,926	$531,926	$531,926	$531,926	$531,926	$531,926	$531,926	$531,926	$531,926	$531,926	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$3,095	$3,095	$3,095	$3,095	$3,095	$3,095	$3,095	$3,095	$3,095	$3,095	$3,095	$3,095	$37,145
b. Debt Component (Line 6 x debt rate) (c) (f)		$526	$526	$526	$526	$526	$526	$526	$526	$526	$526	$526	$526	$6,308
8. Investment Expenses														
a. Depreciation (d)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$3,621	$3,621	$3,621	$3,621	$3,621	$3,621	$3,621	$3,621	$3,621	$3,621	$3,621	$3,621	$43,453

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
410 - Crist Diesel Fuel Oil Remediation														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$20,968	$20,968	$20,968	$20,968	$20,968	$20,968	$20,968	$20,968	$20,968	$20,968	$20,968	$20,968	$20,968	
3. Less: Accumulated Depreciation	$17,958	$18,027	$18,097	$18,167	$18,237	$18,307	$18,377	$18,447	$18,517	$18,587	$18,656	$18,726	$18,796	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$3,010	$2,940	$2,870	$2,800	$2,731	$2,661	$2,591	$2,521	$2,451	$2,381	$2,311	$2,241	$2,171	
6. Average Net Investment		$2,975	$2,905	$2,835	$2,765	$2,696	$2,626	$2,556	$2,486	$2,416	$2,346	$2,276	$2,206	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$17	$17	$16	$16	$16	$15	$15	$14	$14	$14	$13	$13	$181
b. Debt Component (Line 6 x debt rate) (c) (f)		$3	$3	$3	$3	$3	$3	$3	$2	$2	$2	$2	$2	$31
8. Investment Expenses														
a. Depreciation (d)		$70	$70	$70	$70	$70	$70	$70	$70	$70	$70	$70	$70	$839
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$90	$90	$89	$89	$88	$88	$87	$87	$86	$86	$85	$85	$1,050

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
413 - Sodium Injection System														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3. Less: Accumulated Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
a. Less: Capital Recovery Unamortized Balance	($134,738)	($134,738)	($134,738)	($134,738)	($134,738)	($134,738)	($134,738)	($134,738)	($134,738)	($134,738)	($134,738)	($134,738)	($134,738)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$134,738	$134,738	$134,738	$134,738	$134,738	$134,738	$134,738	$134,738	$134,738	$134,738	$134,738	$134,738	$134,738	
6. Average Net Investment		$134,738	$134,738	$134,738	$134,738	$134,738	$134,738	$134,738	$134,738	$134,738	$134,738	$134,738	$134,738	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$784	$784	$784	$784	$784	$784	$784	$784	$784	$784	$784	$784	$9,409
b. Debt Component (Line 6 x debt rate) (c) (f)		$133	$133	$133	$133	$133	$133	$133	$133	$133	$133	$133	$133	$1,598
8. Investment Expenses														
a. Depreciation (d)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$917	$917	$917	$917	$917	$917	$917	$917	$917	$917	$917	$917	$11,007

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
414 - Smith Stormwater Collection System														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$2,764,379	$2,764,379	$2,764,379	$2,764,379	$2,764,379	$2,764,379	$2,764,379	$2,764,379	$2,764,379	$2,764,379	$2,764,379	$2,764,379	$2,764,379	
3. Less: Accumulated Depreciation	$2,446,647	$2,457,474	$2,468,301	$2,479,128	$2,489,955	$2,500,783	$2,511,610	$2,522,437	$2,533,264	$2,544,091	$2,554,918	$2,565,745	$2,576,573	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$317,732	$306,905	$296,078	$285,250	$274,423	$263,596	$252,769	$241,942	$231,115	$220,288	$209,460	$198,633	$187,806	
6. Average Net Investment		$312,318	$301,491	$290,664	$279,837	$269,010	$258,183	$247,355	$236,528	$225,701	$214,874	$204,047	$193,220	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$1,817	$1,754	$1,691	$1,628	$1,565	$1,502	$1,439	$1,376	$1,313	$1,250	$1,187	$1,124	$17,651
b. Debt Component (Line 6 x debt rate) (c) (f)		$309	$298	$287	$277	$266	$255	$244	$234	$223	$212	$202	$191	$2,997
8. Investment Expenses														
a. Depreciation (d)		$10,827	$10,827	$10,827	$10,827	$10,827	$10,827	$10,827	$10,827	$10,827	$10,827	$10,827	$10,827	$129,926
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$12,953	$12,880	$12,806	$12,732	$12,658	$12,585	$12,511	$12,437	$12,364	$12,290	$12,216	$12,142	$150,575

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
415 - Smith Waste Water Treatment Facility														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$643,620	$643,620	$643,620	$643,620	$643,620	$643,620	$643,620	$643,620	$643,620	$643,620	$643,620	$643,620	$643,620	
3. Less: Accumulated Depreciation	($98,415)	($95,894)	($93,373)	($90,852)	($88,332)	($85,811)	($83,290)	($80,769)	($78,248)	($75,727)	($73,207)	($70,686)	($68,165)	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$742,035	$739,514	$736,993	$734,472	$731,951	$729,430	$726,909	$724,389	$721,868	$719,347	$716,826	$714,305	$711,784	
6. Average Net Investment		$740,774	$738,253	$735,732	$733,212	$730,691	$728,170	$725,649	$723,128	$720,607	$718,087	$715,566	$713,045	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$4,311	$4,296	$4,281	$4,267	$4,252	$4,237	$4,223	$4,208	$4,193	$4,179	$4,164	$4,149	$50,761
b. Debt Component (Line 6 x debt rate) (c) (f)		$732	$730	$727	$725	$722	$720	$717	$715	$712	$710	$707	$705	$8,620
8. Investment Expenses														
a. Depreciation (d)		$2,521	$2,521	$2,521	$2,521	$2,521	$2,521	$2,521	$2,521	$2,521	$2,521	$2,521	$2,521	$30,250
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$7,564	$7,547	$7,529	$7,512	$7,495	$7,478	$7,461	$7,444	$7,426	$7,409	$7,392	$7,375	$89,631

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
416 - Daniel Ash Management Project														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$14,939,561	$14,939,561	$14,939,561	$14,939,561	$14,939,561	$14,939,561	$14,939,561	$14,939,561	$14,939,561	$14,939,561	$14,939,561	$14,939,561	$14,939,561	
3. Less: Accumulated Depreciation	$7,729,545	$7,766,900	$7,804,255	$7,841,610	$7,878,965	$7,916,319	$7,953,674	$7,991,029	$8,028,384	$8,065,739	$8,103,094	$8,140,449	$8,177,804	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$7,210,016	$7,172,661	$7,135,306	$7,097,951	$7,060,597	$7,023,242	$6,985,887	$6,948,532	$6,911,177	$6,873,822	$6,836,467	$6,799,112	$6,761,757	
6. Average Net Investment		$7,191,339	$7,153,984	$7,116,629	$7,079,274	$7,041,919	$7,004,564	$6,967,209	$6,929,854	$6,892,499	$6,855,145	$6,817,790	$6,780,435	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$41,849	$41,631	$41,414	$41,196	$40,979	$40,762	$40,544	$40,327	$40,110	$39,892	$39,675	$39,457	$487,836
b. Debt Component (Line 6 x debt rate) (c) (f)		$7,106	$7,070	$7,033	$6,996	$6,959	$6,922	$6,885	$6,848	$6,811	$6,774	$6,737	$6,700	$82,841
8. Investment Expenses														
a. Depreciation (d)		$37,355	$37,355	$37,355	$37,355	$37,355	$37,355	$37,355	$37,355	$37,355	$37,355	$37,355	$37,355	$448,259
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$86,310	$86,056	$85,801	$85,547	$85,293	$85,039	$84,784	$84,530	$84,276	$84,021	$83,767	$83,513	$1,018,936

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
419 - Crist FDEP Agreement for Ozone Attainment														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$39,575,370	$39,575,370	$39,575,370	$39,575,370	$39,575,370	$39,575,370	$39,575,370	$39,575,370	$39,575,370	$39,575,370	$39,575,370	$39,575,370	$39,575,370	
3. Less: Accumulated Depreciation	$14,272,495	$14,413,437	$14,554,380	$14,695,323	$14,836,265	$14,977,208	$15,118,151	$15,259,093	$15,400,036	$15,540,979	$15,681,921	$15,822,864	$15,963,807	
a. Less: Capital Recovery Unamortized Balance	($51,080,981)	($51,080,981)	($51,080,981)	($51,080,981)	($51,080,981)	($51,080,981)	($51,080,981)	($51,080,981)	($51,080,981)	($51,080,981)	($51,080,981)	($51,080,981)	($51,080,981)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$76,383,857	$76,242,914	$76,101,971	$75,961,029	$75,820,086	$75,679,143	$75,538,200	$75,397,258	$75,256,315	$75,115,372	$74,974,430	$74,833,487	$74,692,544	
6. Average Net Investment		$76,313,385	$76,172,443	$76,031,500	$75,890,557	$75,749,615	$75,608,672	$75,467,729	$75,326,786	$75,185,844	$75,044,901	$74,903,958	$74,763,016	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$444,091	$443,270	$442,450	$441,630	$440,810	$439,990	$439,170	$438,349	$437,529	$436,709	$435,889	$435,069	$5,274,955
b. Debt Component (Line 6 x debt rate) (c) (f)		$75,413	$75,274	$75,134	$74,995	$74,856	$74,716	$74,577	$74,438	$74,299	$74,159	$74,020	$73,881	$895,762
8. Investment Expenses														
a. Depreciation (d)		$140,943	$140,943	$140,943	$140,943	$140,943	$140,943	$140,943	$140,943	$140,943	$140,943	$140,943	$140,943	$1,691,312
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$660,446	$659,487	$658,527	$657,568	$656,608	$655,649	$654,689	$653,730	$652,770	$651,811	$650,852	$649,892	$7,862,030

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
422 - Precipitator Upgrades for CAM Compliance														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3. Less: Accumulated Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
a. Less: Capital Recovery Unamortized Balance	($7,632,753)	($7,632,753)	($7,632,753)	($7,632,753)	($7,632,753)	($7,632,753)	($7,632,753)	($7,632,753)	($7,632,753)	($7,632,753)	($7,632,753)	($7,632,753)	($7,632,753)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$7,632,753	$7,632,753	$7,632,753	$7,632,753	$7,632,753	$7,632,753	$7,632,753	$7,632,753	$7,632,753	$7,632,753	$7,632,753	$7,632,753	$7,632,753	
6. Average Net Investment		$7,632,753	$7,632,753	$7,632,753	$7,632,753	$7,632,753	$7,632,753	$7,632,753	$7,632,753	$7,632,753	$7,632,753	$7,632,753	$7,632,753	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$44,417	$44,417	$44,417	$44,417	$44,417	$44,417	$44,417	$44,417	$44,417	$44,417	$44,417	$44,417	$533,008
b. Debt Component (Line 6 x debt rate) (c) (f)		$7,543	$7,543	$7,543	$7,543	$7,543	$7,543	$7,543	$7,543	$7,543	$7,543	$7,543	$7,543	$90,512
8. Investment Expenses														
a. Depreciation (d)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$51,960	$51,960	$51,960	$51,960	$51,960	$51,960	$51,960	$51,960	$51,960	$51,960	$51,960	$51,960	$623,520

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
426 - Air Quality Compliance Program														
Base														
1. Investments														
a. Expenditures/Additions		$223,066	$325,866	$531,466	$428,666	$428,666	$274,466	$274,466	$325,866	$428,666	$428,666	$428,666	$428,666	$4,527,190
b. Clearings to Plant		($471,833,539)	$139,541	$446,891	$139,541	$139,541	$139,541	$139,541	$139,541	$139,541	$139,541	$139,541	$139,541	($469,991,240)
c. Retirements		($471,973,080)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($471,973,080)
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$352,499,577	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$352,499,577
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
h. Regulatory Assets		$352,499,577	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$352,499,577
2. Plant-In-Service/Depreciation Base (a)	$1,346,470,463	$874,636,925	$874,776,466	$875,223,356	$875,362,897	$875,502,438	$875,641,979	$875,781,520	$875,921,061	$876,060,601	$876,200,142	$876,339,683	$876,479,224	
3. Less: Accumulated Depreciation	$336,405,088	$219,802,457	$222,145,211	$224,488,732	$226,833,021	$229,177,566	$231,522,367	$233,867,424	$236,212,737	$238,558,306	$240,904,130	$243,250,210	$245,596,546	
a. Less: Capital Recovery Unamortized Balance	($353,944,656)	($706,081,536)	($704,250,091)	($702,418,647)	($700,587,202)	($698,755,757)	($696,924,312)	($695,092,867)	($693,261,422)	($691,429,977)	($689,598,532)	($687,767,088)	($685,935,643)	
4. CWIP	$10,057,842	$10,141,367	$10,327,692	$10,412,267	$10,701,392	$10,990,517	$11,125,442	$11,260,367	$11,446,692	$11,735,817	$12,024,942	$12,314,067	$12,603,192	
5. Net Investment (Lines 2 - 3 + 4)	$1,374,067,874	$1,371,057,371	$1,367,209,038	$1,363,565,538	$1,359,818,469	$1,356,071,146	$1,352,169,366	$1,348,267,330	$1,344,416,438	$1,340,668,090	$1,336,919,487	$1,333,170,628	$1,329,421,513	
6. Average Net Investment		$1,372,562,622	$1,369,133,204	$1,365,387,288	$1,361,692,004	$1,357,944,808	$1,354,120,256	$1,350,218,348	$1,346,341,884	$1,342,542,264	$1,338,793,789	$1,335,045,057	$1,331,296,070	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$7,987,357	$7,967,400	$7,945,601	$7,924,097	$7,902,291	$7,880,035	$7,857,328	$7,834,770	$7,812,659	$7,790,846	$7,769,031	$7,747,214	$94,418,628
b. Debt Component (Line 6 x debt rate) (c) (f)		$1,356,366	$1,352,977	$1,349,276	$1,345,624	$1,341,921	$1,338,142	$1,334,286	$1,330,455	$1,326,700	$1,322,996	$1,319,292	$1,315,587	$16,033,622
8. Investment Expenses														
a. Depreciation (d)		$2,870,872	$2,342,753	$2,343,521	$2,344,289	$2,344,545	$2,344,801	$2,345,057	$2,345,313	$2,345,569	$2,345,824	$2,346,080	$2,346,336	$28,664,961
b. Amortization (e)		$362,697	$1,831,445	$1,831,445	$1,831,445	$1,831,445	$1,831,445	$1,831,445	$1,831,445	$1,831,445	$1,831,445	$1,831,445	$1,831,445	$20,508,590
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$12,577,292	$13,494,575	$13,469,843	$13,445,456	$13,420,202	$13,394,422	$13,368,116	$13,341,983	$13,316,373	$13,291,111	$13,265,847	$13,240,582	$159,625,802

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.

(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.

(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.

(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.

(e) Applicable amortization period(s). See Depreciation Schedule 4P.

(f) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
426 - Air Quality Compliance Program														
Distribution														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	
3. Less: Accumulated Depreciation	$494	$497	$499	$502	$505	$508	$511	$513	$516	$519	$522	$525	$527	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$819	$816	$813	$810	$808	$805	$802	$799	$796	$794	$791	$788	$785	
6. Average Net Investment		$817	$815	$812	$809	$806	$803	$801	$798	$795	$792	$789	$787	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$56
b. Debt Component (Line 6 x debt rate) (c) (f)		$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$10
8. Investment Expenses														
a. Depreciation (d)		$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$34
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$8	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8	$99

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
426 - Air Quality Compliance Program														
General														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$7,005	$7,005	$7,005	$7,005	$7,005	$7,005	$7,005	$7,005	$7,005	$7,005	$7,005	$7,005	$7,005	
3. Less: Accumulated Depreciation	$1,839	$1,870	$1,900	$1,930	$1,961	$1,991	$2,021	$2,052	$2,082	$2,112	$2,143	$2,173	$2,204	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$5,165	$5,135	$5,105	$5,074	$5,044	$5,014	$4,983	$4,953	$4,922	$4,892	$4,862	$4,831	$4,801	
6. Average Net Investment		$5,150	$5,120	$5,089	$5,059	$5,029	$4,998	$4,968	$4,938	$4,907	$4,877	$4,847	$4,816	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$30	$30	$30	$29	$29	$29	$29	$29	$29	$28	$28	$28	$348
b. Debt Component (Line 6 x debt rate) (c) (f)		$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$59
8. Investment Expenses														
a. Depreciation (d)		$30	$30	$30	$30	$30	$30	$30	$30	$30	$30	$30	$30	$364
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$65	$65	$65	$65	$65	$64	$64	$64	$64	$64	$63	$63	$771

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
426 - Air Quality Compliance Program														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		($109,901)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($109,901)
c. Retirements		($109,901)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($109,901)
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$191,926	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$191,926
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
h. Regulatory Assets		$191,926	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$191,926
2. Plant-In-Service/Depreciation Base (a)	$1,345,887	$1,235,985	$1,235,985	$1,235,985	$1,235,985	$1,235,985	$1,235,985	$1,235,985	$1,235,985	$1,235,985	$1,235,985	$1,235,985	$1,235,985	
3. Less: Accumulated Depreciation	$294,409	$379,026	$381,349	$383,673	$385,996	$388,320	$390,644	$392,967	$395,291	$397,614	$399,938	$402,261	$404,585	
a. Less: Capital Recovery Unamortized Balance	$0	($191,414)	($190,615)	($189,815)	($189,015)	($188,216)	($187,416)	($186,616)	($185,816)	($185,017)	($184,217)	($183,417)	($182,618)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,051,477	$1,048,374	$1,045,251	$1,042,127	$1,039,004	$1,035,881	$1,032,757	$1,029,634	$1,026,511	$1,023,388	$1,020,264	$1,017,141	$1,014,018	
6. Average Net Investment		$1,049,925	$1,046,812	$1,043,689	$1,040,566	$1,037,442	$1,034,319	$1,031,196	$1,028,073	$1,024,949	$1,021,826	$1,018,703	$1,015,579	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$6,110	$6,092	$6,074	$6,055	$6,037	$6,019	$6,001	$5,983	$5,964	$5,946	$5,928	$5,910	$72,119
b. Debt Component (Line 6 x debt rate) (c) (f)		$1,038	$1,034	$1,031	$1,028	$1,025	$1,022	$1,019	$1,016	$1,013	$1,010	$1,007	$1,004	$12,247
8. Investment Expenses														
a. Depreciation (d)		$2,591	$2,324	$2,324	$2,324	$2,324	$2,324	$2,324	$2,324	$2,324	$2,324	$2,324	$2,324	$28,151
b. Amortization (e)		$512	$800	$800	$800	$800	$800	$800	$800	$800	$800	$800	$800	$9,309
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$10,251	$10,249	$10,228	$10,207	$10,186	$10,164	$10,143	$10,122	$10,101	$10,079	$10,058	$10,037	$121,825

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.

(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.

(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.

(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.

(e) Applicable amortization period(s). See Depreciation Schedule 4P.

(f) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
426 - Air Quality Compliance Program														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		($164,093,950)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($164,093,950)
c. Retirements		($164,093,950)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($164,093,950)
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$237,370,842	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$237,370,842
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
h. Regulatory Assets		$237,370,842	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$237,370,842
2. Plant-In-Service/Depreciation Base (a)	$164,491,788	$397,838	$397,838	$397,838	$397,838	$397,838	$397,838	$397,838	$397,838	$397,838	$397,838	$397,838	$397,838	
3. Less: Accumulated Depreciation	($73,359,895)	$240,860	$243,224	$245,587	$247,950	$250,314	$252,677	$255,040	$257,404	$259,767	$262,130	$264,494	$266,857	
a. Less: Capital Recovery Unamortized Balance	($38,548)	($236,860,517)	($235,870,832)	($234,881,147)	($233,891,463)	($232,901,778)	($231,912,093)	($230,922,409)	($229,932,724)	($228,943,039)	($227,953,355)	($226,963,670)	($225,973,986)	
4. CWIP	$44,237	$44,237	$44,237	$44,237	$44,237	$44,237	$44,237	$44,237	$44,237	$44,237	$44,237	$44,237	$44,237	
5. Net Investment (Lines 2 - 3 + 4)	$237,934,468	$237,061,732	$236,069,684	$235,077,636	$234,085,588	$233,093,540	$232,101,492	$231,109,444	$230,117,396	$229,125,348	$228,133,300	$227,141,252	$226,149,204	
6. Average Net Investment		$237,498,100	$236,565,708	$235,573,660	$234,581,612	$233,589,564	$232,597,516	$231,605,468	$230,613,420	$229,621,372	$228,629,324	$227,637,276	$226,645,228	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$1,382,073	$1,376,647	$1,370,874	$1,365,101	$1,359,328	$1,353,555	$1,347,782	$1,342,009	$1,336,236	$1,330,463	$1,324,690	$1,318,917	$16,207,677
b. Debt Component (Line 6 x debt rate) (c) (f)		$234,696	$233,774	$232,794	$231,814	$230,833	$229,853	$228,873	$227,892	$226,912	$225,931	$224,951	$223,971	$2,752,293
8. Investment Expenses														
a. Depreciation (d)		$323,863	$2,363	$2,363	$2,363	$2,363	$2,363	$2,363	$2,363	$2,363	$2,363	$2,363	$2,363	$349,860
b. Amortization (e)		$548,873	$989,685	$989,685	$989,685	$989,685	$989,685	$989,685	$989,685	$989,685	$989,685	$989,685	$989,685	$11,435,404
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$2,489,505	$2,602,470	$2,595,716	$2,588,963	$2,582,209	$2,575,456	$2,568,703	$2,561,949	$2,555,196	$2,548,443	$2,541,689	$2,534,936	$30,745,235

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.

(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.

(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.

(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.

(e) Applicable amortization period(s). See Depreciation Schedule 4P.

(f) For solar projects the return on investment calculation is comprised of two parts:

Return on the Average Net Investment: See footnotes (b) and (c).

Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
426 - Air Quality Compliance Program														
Transmission														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (a)	$6,072,386	$6,072,386	$6,072,386	$6,072,386	$6,072,386	$6,072,386	$6,072,386	$6,072,386	$6,072,386	$6,072,386	$6,072,386	$6,072,386	$6,072,386	
3. Less: Accumulated Depreciation	$1,897,461	$1,911,722	$1,925,983	$1,940,244	$1,954,505	$1,968,766	$1,983,027	$1,997,288	$2,011,549	$2,025,810	$2,040,071	$2,054,332	$2,068,593	
a. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$4,174,925	$4,160,664	$4,146,403	$4,132,142	$4,117,881	$4,103,620	$4,089,359	$4,075,098	$4,060,837	$4,046,576	$4,032,315	$4,018,054	$4,003,793	
6. Average Net Investment		$4,167,795	$4,153,534	$4,139,273	$4,125,012	$4,110,751	$4,096,490	$4,082,229	$4,067,968	$4,053,707	$4,039,446	$4,025,185	$4,010,924	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$24,254	$24,171	$24,088	$24,005	$23,922	$23,839	$23,756	$23,673	$23,590	$23,507	$23,424	$23,341	$285,567
b. Debt Component (Line 6 x debt rate) (c) (f)		$4,119	$4,105	$4,090	$4,076	$4,062	$4,048	$4,034	$4,020	$4,006	$3,992	$3,978	$3,964	$48,493
8. Investment Expenses														
a. Depreciation (d)		$14,261	$14,261	$14,261	$14,261	$14,261	$14,261	$14,261	$14,261	$14,261	$14,261	$14,261	$14,261	$171,132
b. Amortization (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$42,633	$42,536	$42,439	$42,342	$42,245	$42,148	$42,051	$41,954	$41,857	$41,760	$41,662	$41,565	$505,192

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
427 - General Water Quality														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Cost of Removal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
f. Transfer Adjustments		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
g. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
h. Regulatory Assets		$14,273	$826,347	$14,273	$826,347	$1,014,074	$202,000	$2,067,652	$0	$0	$0	$0	$0	$4,964,966
2. Plant-In-Service/Depreciation Base (a)	$996,766	$996,766	$996,766	$996,766	$996,766	$996,766	$996,766	$996,766	$996,766	$996,766	$996,766	$996,766	$996,766	
3. Less: Accumulated Depreciation	$129,535	$132,857	$136,180	$139,502	$142,825	$146,147	$149,470	$152,792	$156,115	$159,438	$162,760	$166,083	$169,405	
a. Less: Capital Recovery Unamortized Balance	($13,505,519)	($13,465,387)	($14,235,929)	($14,192,995)	($14,960,734)	($15,913,133)	($16,051,431)	($18,051,598)	($17,980,667)	($17,909,736)	($17,838,806)	($17,767,875)	($17,696,944)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$14,372,750	$14,329,296	$15,096,515	$15,050,258	$15,814,675	$16,763,751	$16,898,727	$18,895,571	$18,821,318	$18,747,065	$18,672,811	$18,598,558	$18,524,305	
6. Average Net Investment		$14,351,023	$14,712,905	$15,073,386	$15,432,467	$16,289,213	$16,831,239	$17,897,149	$18,858,445	$18,784,191	$18,709,938	$18,635,685	$18,561,431	
7. Return on Average Net Investment														
a. Equity Component (Line 6 x equity rate grossed up for taxes) (b) (f)		$83,513	$85,619	$87,717	$89,806	$94,792	$97,946	$104,149	$109,743	$109,311	$108,879	$108,447	$108,015	$1,187,935
b. Debt Component (Line 6 x debt rate) (c) (f)		$14,182	$14,539	$14,896	$15,250	$16,097	$16,633	$17,686	$18,636	$18,563	$18,489	$18,416	$18,342	$201,728
8. Investment Expenses														
a. Depreciation (d)		$3,323	$3,323	$3,323	$3,323	$3,323	$3,323	$3,323	$3,323	$3,323	$3,323	$3,323	$3,323	$39,871
b. Amortization (e)		$54,405	$55,806	$57,207	$58,608	$61,675	$63,702	$67,485	$70,931	$70,931	$70,931	$70,931	$70,931	$773,541
c. Dismantlement		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 + 8)		$155,422	$159,286	$163,141	$166,987	$175,887	$181,603	$192,642	$202,632	$202,127	$201,621	$201,116	$200,610	$2,203,075

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Depreciation Schedule 4P.
(b) The Equity Component for the period has been grossed up for taxes. The approved ROE is 10.6%. See Schedule 8P.
(c) The Debt Component for the period is based on the Forecasted Surveillance Report. See Schedule 8P.
(d) Applicable depreciation rate or rates. See Depreciation Schedule 4P.
(e) Applicable amortization period(s). See Depreciation Schedule 4P.
(f) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance. See Schedule 8P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-4P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
1. Investments														
a. Purchases/Transfers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Sales/Transfers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Auction Proceeds/Others	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Working Capital - Dr (Cr)														
a. 158.100 Allowance Inventory	$6,290,671	$6,290,671	$6,290,671	$6,290,671	$6,290,671	$6,290,671	$6,290,671	$6,290,671	$6,290,671	$6,290,671	$6,290,671	$6,290,671	$6,290,671	
b. 158.200 Allowances Withheld	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
c. 182.300 Other Regulatory Assets - Losses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
d. 254.900 Other Regulatory Liabilities - Gains	($189)	($189)	($189)	($174)	($174)	($174)	($160)	($160)	($160)	($145)	($145)	($145)	($130)	
3. Total Working Capital	$6,290,482	$6,290,482	$6,290,482	$6,290,497	$6,290,497	$6,290,497	$6,290,511	$6,290,511	$6,290,511	$6,290,526	$6,290,526	$6,290,526	$6,290,541	
4. Average Total Working Capital Balance		$6,290,482	$6,290,482	$6,290,489	$6,290,497	$6,290,497	$6,290,504	$6,290,511	$6,290,511	$6,290,519	$6,290,526	$6,290,526	$6,290,533	
5. Return on Average Total Working Capital Balance														
a. Equity Component (Line 4 x equity rate grossed up for taxes) (a)		$36,606	$36,606	$36,606	$36,606	$36,606	$36,606	$36,606	$36,606	$36,606	$36,606	$36,606	$36,607	$439,276
b. Debt Component (Line 4 x debt rate)		$6,216	$6,216	$6,216	$6,216	$6,216	$6,216	$6,216	$6,216	$6,216	$6,216	$6,216	$6,216	$74,595
6. Total Return Component (a)		$42,822	$42,822	$42,823	$42,823	$42,823	$42,823	$42,823	$42,823	$42,823	$42,823	$42,823	$42,823	$513,872
7. Expenses														
a. 411.800 Gains from Dispositions of Allowances		$0	$0	($15)	$0	$0	($15)	$0	$0	($15)	$0	$0	($15)	($59)
b. 411.900 Losses from Dispositions of Allowances		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. 509.000 Allowance Expense		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8. Net Expenses (Lines 7a + 7b + 7c)		$0	$0	($15)	$0	$0	($15)	$0	$0	($15)	$0	$0	($15)	($59)
9. Total System Recoverable Expenses (Lines 6 + 8)		$42,822	$42,822	$42,808	$42,823	$42,823	$42,808	$42,823	$42,823	$42,808	$42,823	$42,823	$42,808	$513,813

Notes:

(a) The approved ROE is 10.6%.

(b) Line 6 is reported on Schedule 3P.

(c) Line 8 is reported on schedule 2P.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Return On Capital Investments, Depreciation and Taxes

Form 42-4P

January 2022 through December 2022

	Beginning of Period	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	Total
1. Regulatory Asset Balance (b)	$16,482,509	$16,363,930	$16,245,351	$16,126,772	$16,008,193	$15,889,614	$15,771,035	$15,652,456	$15,533,877	$15,415,298	$15,296,719	$15,178,140	$15,059,561	
2. Less: Amortization (c)	($118,579)	($118,579)	($118,579)	($118,579)	($118,579)	($118,579)	($118,579)	($118,579)	($118,579)	($118,579)	($118,579)	($118,579)	($118,579)	
3. Net Regulatory Asset Balance (Lines 1+2) (a)	$16,363,930	$16,245,351	$16,126,772	$16,008,193	$15,889,614	$15,771,035	$15,652,456	$15,533,877	$15,415,298	$15,296,719	$15,178,140	$15,059,561	$14,940,982	
4. Average Net Regulatory Asset Balance		$16,304,641	$16,186,062	$16,067,483	$15,948,904	$15,830,325	$15,711,746	$15,593,167	$15,474,588	$15,356,009	$15,237,430	$15,118,851	$15,000,272	
5. Return on Average Net Regulatory Asset Balance														
a. Equity Component (Line 4 x equity rate grossed up for taxes) (d)		$94,882	$94,192	$93,502	$92,811	$92,121	$91,431	$90,741	$90,051	$89,361	$88,671	$87,981	$87,291	$1,093,036
b. Debt Component (Line 4 x debt rate)		$16,112	$15,995	$15,878	$15,761	$15,644	$15,526	$15,409	$15,292	$15,175	$15,058	$14,940	$14,823	$185,613
6. Amortization Expense														
a. Recoverable Costs		$118,579	$118,579	$118,579	$118,579	$118,579	$118,579	$118,579	$118,579	$118,579	$118,579	$118,579	$118,579	$1,422,948
b. Other (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7. Total System Recoverable Expenses (Lines 5 + 6)		$229,573	$228,766	$227,958	$227,151	$226,344	$225,537	$224,730	$223,922	$223,115	$222,308	$221,501	$220,693	$2,701,598

Notes:

(a) End of period Regulatory Asset Balance.

(b) Beginning of period Regulatory Asset Balance.

(c) Regulatory Asset has a 15 year amortization period.

(d) The equity component has been grossed up for taxes. The approved ROE is 10.60%.

(e) Description and reason for "Other" adjustments to regulatory asset.

Florida Power & Light Company
Environmental Cost Recovery Clause **FORM 42-4P**
2022 Annual Capital Depreciation Schedule

Project	Function	Unit	Utility	DEPR RATE	12/1/2022
002-LOW NOX BURNER TECHNOLOGY	02 - Steam Generation Plant	Turkey Pt U1	31200	0.00%	-
002-LOW NOX BURNER TECHNOLOGY Total					-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	CapeCanaveral U1	31200	0.00%	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee Comm	31200	7.62%	65,605
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee U1	31100	1.74%	56,430
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee U1	31200	4.64%	424,505
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee U2	31100	1.83%	56,333
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee U2	31200	4.99%	468,728
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin Comm	31200	4.45%	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin Comm	31650	20.00%	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin Comm	31670	14.29%	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin U1	31100	2.68%	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin U1	31200	4.53%	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin U2	31100	2.39%	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin U2	31200	4.64%	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Scherer U4	31200	2.79%	515,653
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	SJRPP - Comm	31100	1.09%	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	SJRPP - Comm	31200	1.44%	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Turkey Pt Comm	31100	0.00%	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Turkey Pt Comm	31200	0.00%	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Turkey Pt U1	31100	0.00%	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Turkey Pt U1	31200	0.00%	-
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtLauderdale Comm	34100	2.20%	-
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtLauderdale Comm	34500	1.60%	-
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtLauderdale GTs	34300	8.25%	10,225
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtLauderdale U4	34300	4.11%	-
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtLauderdale U5	34300	5.00%	-
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtMyers U2	34100	2.34%	-
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtMyers U2	34300	3.46%	365,000
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtMyers U3	34100	3.38%	6,098
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtMyers U3	34300	4.54%	71,939
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtMyers U3 SC Peaker	34300	3.04%	69,082
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Manatee U3	34300	3.35%	87,691
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Martin U3	34300	4.49%	615,469
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Martin U4	34300	3.92%	598,036
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Putnam Comm	34100	0.00%	-
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Putnam Comm	34300	0.00%	-
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Sanford Comm	34300	0.00%	-
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Sanford U4	34300	4.00%	310,021
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Sanford U5	34300	4.12%	273,035
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Martin U8	34300	3.37%	13,693
003-CONTINUOUS EMISSION MONITORING Total					**4,007,544**
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Manatee Comm	31100	3.17%	3,111,263
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Manatee Comm	31200	7.62%	174,543
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Manatee U1	31200	4.64%	104,845
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Manatee U2	31200	4.99%	127,429
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Martin Comm	31100	2.52%	65,093
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Martin Comm	31200	4.45%	-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Martin U1	31100	2.68%	-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Martin U2	31100	2.39%	-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	SJRPP - Comm	31100	1.09%	-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	SJRPP - Comm	31200	1.44%	-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Turkey Pt Comm	31100	0.00%	-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Turkey Pt U1	31100	0.00%	-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	FtLauderdale Comm	34200	3.09%	898,111
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	FtLauderdale GTs	34200	4.73%	584,290
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	FtMyers GTs	34200	7.84%	133,479
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	FtMyers U3	34200	3.58%	18,616
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	Martin Comm	34200	2.42%	455,941
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	PtEverglades GTs	34200	0.00%	-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	Putnam Comm	34200	0.00%	-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	08 - General Plant	General Plant	39000	1.50%	8,225,223
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS Total					**13,898,833**
007-RELOCATE TURBINE LUBE OIL PIPING	03 - Nuclear Generation Plant	StLucie U1	32300	5.11%	31,030
007-RELOCATE TURBINE LUBE OIL PIPING Total					**31,030**
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Manatee Comm	31100	3.17%	46,882
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Manatee Comm	31650	20.00%	-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Manatee Comm	31670	14.29%	-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Manatee U1	31100	1.74%	51,165
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Martin Comm	31600	3.79%	-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Martin Comm	31650	20.00%	280,886
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Martin Comm	31670	14.29%	157,547
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Turkey Pt Comm	31100	0.00%	-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Turkey Pt Comm	31650	20.00%	-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	CapeCanaveral U1CC	34100	2.69%	5,334
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	CapeCanaveral U1CC	34650	20.00%	-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	CapeCanaveral U1CC	34670	14.29%	-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	FtLauderdale Comm	34100	2.20%	358,605
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	FtMyers Comm	34650	20.00%	-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	FtMyers U2	34100	2.34%	558,534
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	PtEverglades U5	34100	2.64%	22,550
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	Putnam Comm	34650	20.00%	-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	Riviera Comm	34650	20.00%	-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	Sanford Comm	34100	2.40%	15,922
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	07 - Distribution Plant - Electric	Mass Distribution Plant	36670	2.00%	2,995
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	08 - General Plant	General Plant	39000	1.50%	4,413
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	08 - General Plant	General Plant	39190	33.33%	-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT Total					**1,504,834**
010-REROUTE STORMWATER RUNOFF	03 - Nuclear Generation Plant	StLucie Comm	32100	2.25%	117,794
010-REROUTE STORMWATER RUNOFF Total					**117,794**
012-SCHERER DISCHARGE PIPELINE	02 - Steam Generation Plant	Scherer Comm	31100	1.51%	524,873
012-SCHERER DISCHARGE PIPELINE	02 - Steam Generation Plant	Scherer Comm	31200	2.23%	328,762
012-SCHERER DISCHARGE PIPELINE	02 - Steam Generation Plant	Scherer Comm	31400	2.08%	689
012-SCHERER DISCHARGE PIPELINE Total					**854,324**
016-ST.LUCIE TURTLE NETS	03 - Nuclear Generation Plant	StLucie Comm	32100	2.25%	6,909,559
016-ST.LUCIE TURTLE NETS Total					**6,909,559**
020-WASTEWATER/STORMWATER DISCH ELIMINATION	02 - Steam Generation Plant	Martin U1	31200	4.53%	-
020-WASTEWATER/STORMWATER DISCH ELIMINATION	02 - Steam Generation Plant	Martin U2	31200	4.64%	-
020-WASTEWATER/STORMWATER DISCH ELIMINATION Total					-
022-PIPELINE INTEGRITY MANAGEMENT	02 - Steam Generation Plant	Manatee Comm	31100	3.17%	601,217
022-PIPELINE INTEGRITY MANAGEMENT	02 - Steam Generation Plant	Martin Comm	31100	2.52%	2,271,574
022-PIPELINE INTEGRITY MANAGEMENT Total					**2,872,791**
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee Comm	31100	3.17%	1,243,306

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Project	Function	Unit	Utility	DEPR RATE	12/1/2022
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee Comm	31200	7.62%	33,272
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee Comm	31500	2.34%	26,325
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee U1	31200	4.64%	45,750
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee U2	31200	4.99%	37,431
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Martin Comm	31100	2.52%	37,158
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Martin Comm	31500	3.57%	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Turkey Pt Comm	31100	0.00%	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Turkey Pt Comm	31500	0.00%	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Turkey Pt U1	31100	0.00%	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	StLucie U1	32300	5.11%	712,225
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	StLucie U1	32400	3.20%	745,335
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	StLucie U2	32300	3.86%	552,390
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	Turkey Pt Comm	32100	3.13%	990,124
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	Turkey Pt Comm	32570	14.29%	245,362
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtLauderdale Comm	34100	2.20%	189,219
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtLauderdale Comm	34200	3.09%	1,480,169
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtLauderdale Comm	34300	5.20%	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtLauderdale GTs	34100	4.18%	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtLauderdale GTs	34200	4.73%	513,250
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtLauderdale U6 SC Peaker	34100	2.69%	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtMyers GTs	34100	7.40%	98,715
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtMyers GTs	34200	7.84%	629,983
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtMyers GTs	34500	7.77%	12,430
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtMyers U2	34100	2.34%	361,382
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtMyers U2	34300	3.46%	49,727
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtMyers U3	34500	3.40%	12,430
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Martin Comm	34100	2.24%	982,202
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	PtEverglades Comm	34200	2.90%	2,728,283
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	PtEverglades GTs	34100	0.00%	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	PtEverglades GTs	34200	0.00%	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	PtEverglades GTs	34500	0.00%	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	PtEverglades U5	34200	2.90%	286,434
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Putnam Comm	34100	0.00%	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Putnam Comm	34200	0.00%	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Putnam Comm	34500	0.00%	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Sanford Comm	34100	2.40%	288,383
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Martin U8	34200	2.70%	84,868
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electric	Radial-Retail	35200	1.70%	6,946
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electric	Transmission Plant - Electric	35200	1.70%	1,145,114
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electric	Transmission Plant - Electric	35300	2.04%	2,903,037
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electric	Transmission Plant - Electric	35800	1.87%	65,655
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	07 - Distribution Plant - Electric	Mass Distribution Plant	36100	1.75%	3,461,675
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	07 - Distribution Plant - Electric	Mass Distribution Plant	36670	2.00%	70,499
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	08 - General Plant	General Plant	39000	1.50%	150,066
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES Total					**20,189,146**
024-GAS REBURN	02 - Steam Generation Plant	Manatee U1	31200	4.64%	16,470,024
024-GAS REBURN	02 - Steam Generation Plant	Manatee U2	31200	4.99%	15,393,694
024-GAS REBURN Total					**31,863,719**
025-PPE ESP TECHNOLOGY	02 - Steam Generation Plant	PtEverglades U1	31100	0.00%	-
025-PPE ESP TECHNOLOGY Total					**-**
026-UST REPLACEMENT/REMOVAL	08 - General Plant	General Plant	39000	1.50%	115,447
026-UST REPLACEMENT/REMOVAL Total					**115,447**
027 - Lowest Quality Water Source	05 - Other Generation Plant	Sanford Comm	34300	7.96%	-
027 - Lowest Quality Water Source Total					**-**
028-CWA 316B PHASE II RULE	05 - Other Generation Plant	CapeCanaveral Comm CC	34100	2.69%	771,310
028-CWA 316B PHASE II RULE Total					**771,310**
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee Comm	31100	3.17%	102,052
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee U1	31200	4.64%	20,059,060
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee U1	31400	4.03%	7,240,124
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee U2	31200	4.99%	20,457,354
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee U2	31400	3.72%	7,905,907
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin Comm	31200	4.45%	-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin Comm	31400	3.48%	-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin U1	31200	4.53%	-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin U1	31400	3.35%	-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin U2	31200	4.64%	-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin U2	31400	4.79%	-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer Comm U3&4	31200	2.32%	5,725,205
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31100	2.30%	82,366,984
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31200	2.79%	254,626,928
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31400	1.89%	(94,224)
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31500	2.49%	19,615,426
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31600	1.88%	399,586
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31670	14.29%	-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	SJRPP - Comm	31200	1.44%	-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	SJRPP - Comm	31500	1.30%	-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	SJRPP - Comm	31600	1.31%	-
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	FtLauderdale GTs	34300	8.25%	110,242
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	FtMyers GTs	34300	8.22%	57,855
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	Martin Comm	34100	2.24%	699,143
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	Martin Comm	34300	2.56%	244,343
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	Martin Comm	34500	2.04%	292,499
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	PtEverglades GTs	34300	0.00%	-
031-CLEAN AIR INTERSTATE RULE-CAIR	07 - Distribution Plant - Electric	Mass Distribution Plant	36500	2.57%	1,313
031-CLEAN AIR INTERSTATE RULE-CAIR Total					**419,809,797**
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	Scherer Comm U3&4	31200	2.32%	(1,234,037)
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	Scherer U4	31100	2.30%	-
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	Scherer U4	31200	2.79%	110,565,526
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	Scherer U4	31500	2.49%	-
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	SJRPP - Comm	31200	1.44%	-
033-CLEAN AIR MERCURY RULE-CAMR	03 - Nuclear Generation Plant	Scherer U4	31200	2.79%	1,682
033-CLEAN AIR MERCURY RULE-CAMR Total					**109,333,171**
034-PSL COOLING WATER SYSTEM INSPECTION & MAINTENANCE	03 - Nuclear Generation Plant	StLucie Comm	32100	2.25%	-
034-PSL COOLING WATER SYSTEM INSPECTION & MAINTENANCE Total					**-**
035-MARTIN PLANT DRINKING WATER COMP	02 - Steam Generation Plant	Martin Comm	31100	2.52%	-
035-MARTIN PLANT DRINKING WATER COMP Total					**-**
036-LOW LEV RADI WSTE-LLW	03 - Nuclear Generation Plant	StLucie Comm	32100	2.25%	7,601,405
036-LOW LEV RADI WSTE-LLW	03 - Nuclear Generation Plant	Turkey Pt Comm	32100	3.13%	9,855,399
036-LOW LEV RADI WSTE-LLW Total					**17,456,804**
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34000	0.00%	255,507
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34100	3.49%	5,263,916
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34300	3.36%	115,352,982
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34500	3.65%	26,805,653

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Project	Function	Unit	Utility	DEPR RATE	12/1/2022
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34630	33.33%	5,261
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34650	20.00%	24,247
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34670	14.29%	154,831
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34800	10.00%	20,100
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35200	1.70%	7,427
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35300	2.04%	995,394
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35310	2.64%	1,695,869
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35500	2.32%	394,418
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35600	2.38%	191,358
037-DE SOTO SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36100	1.75%	540,994
037-DE SOTO SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36200	1.90%	1,890,938
037-DE SOTO SOLAR PROJECT	08 - General Plant	General Plant	39220	10.00%	28,426
037-DE SOTO SOLAR PROJECT	08 - General Plant	General Plant	39720	14.29%	-
037-DE SOTO SOLAR PROJECT Total					**153,627,320**
038-SPACE COAST SOLAR PROJECT	01 - Intangible Plant	Intangible Plant	30300	various	6,359,027
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast Solar	34100	3.45%	3,893,263
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast Solar	34300	3.30%	51,558,627
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast Solar	34500	3.51%	6,126,699
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast Solar	34630	33.33%	1,105
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast Solar	34650	20.00%	-
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast Solar	34670	14.29%	-
038-SPACE COAST SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35300	2.04%	928,529
038-SPACE COAST SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35310	2.64%	1,328,699
038-SPACE COAST SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36100	1.75%	274,858
038-SPACE COAST SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36200	1.90%	62,689
038-SPACE COAST SOLAR PROJECT	08 - General Plant	General Plant	39220	10.00%	31,858
038-SPACE COAST SOLAR PROJECT	08 - General Plant	General Plant	39720	14.29%	-
038-SPACE COAST SOLAR PROJECT Total					**70,565,354**
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34000	0.00%	216,844
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34100	2.99%	20,798,049
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34300	2.88%	400,558,990
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34500	2.99%	4,171,693
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34600	2.85%	56,448
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34650	20.00%	-
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34670	14.29%	143,061
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin U8	34300	3.37%	423,126
039-MARTIN SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35500	2.32%	603,692
039-MARTIN SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35600	2.38%	364,159
039-MARTIN SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36500	2.57%	-
039-MARTIN SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36660	1.42%	94,476
039-MARTIN SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36760	1.96%	2,728
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	39220	10.00%	121,101
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	39240	2.63%	332,682
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	39290	4.99%	88,938
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	39420	14.29%	-
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	39720	14.29%	-
039-MARTIN SOLAR PROJECT Total					**427,975,986**
041-PRV MANATEE HEATING SYSTEM	05 - Other Generation Plant	CapeCanaveral Comm	34300	0.00%	4,042,459
041-PRV MANATEE HEATING SYSTEM	05 - Other Generation Plant	Dania Beach EC U7	34300	44 mos.	-
041-PRV MANATEE HEATING SYSTEM	05 - Other Generation Plant	FtLauderdale Comm U4&5	34300	44 mos.	7,930,276
041-PRV MANATEE HEATING SYSTEM	05 - Other Generation Plant	FtMyers U2	34300	3.46%	5,603,547
041-PRV MANATEE HEATING SYSTEM	06 - Transmission Plant - Electric	Transmission Plant - Electric	35300	various	276,404
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36100	various	73,267
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36200	various	471,542
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36410	various	137,247
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36420	various	36,431
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36500	various	307,599
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36660	various	221,326
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36760	various	168,841
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36910	various	607
041-PRV MANATEE HEATING SYSTEM Total					**19,269,547**
042-PTN COOLING CANAL MONITORING SYS	03 - Nuclear Generation Plant	Turkey Pt Comm	32100	3.13%	67,621,510
042-PTN COOLING CANAL MONITORING SYS	03 - Nuclear Generation Plant	Turkey Pt Comm	32500	3.67%	1,037,522
042-PTN COOLING CANAL MONITORING SYS	03 - Nuclear Generation Plant	Turkey Pt Comm	32550	20.00%	544,822
042-PTN COOLING CANAL MONITORING SYS	05 - Other Generation Plant	Turkey Pt U5	34100	2.33%	-
042-PTN COOLING CANAL MONITORING SYS Total					**69,203,854**
044-Barley Barber Swamp Iron Mitiga	02 - Steam Generation Plant	Martin Comm	31100	2.52%	164,719
044-Barley Barber Swamp Iron Mitiga Total					**164,719**
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee Comm	31200	7.62%	153,660
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U1	31200	4.64%	44,485,716
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U1	31500	4.11%	4,524,074
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U1	31600	3.91%	1,021,918
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U2	31200	4.99%	52,285,732
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U2	31500	4.48%	4,793,798
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U2	31600	4.79%	1,174,454
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U1	31200	4.53%	-
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U1	31500	3.12%	-
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U1	31600	3.81%	-
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U2	31200	4.64%	-
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U2	31500	3.56%	-
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U2	31600	4.31%	-
045-800 MW UNIT ESP PROJECT Total					**108,439,353**
047-NPDES Permit Renewal Requirement	03 - Nuclear Generation Plant	StLucie Comm	32100	2.25%	-
047-NPDES Permit Renewal Requirement	03 - Nuclear Generation Plant	StLucie Comm	32300	7.22%	2,801,208
047-NPDES Permit Renewal Requirement Total					**2,801,208**
050-STEAM ELEC EFFLUENT GUIDELI REV	02 - Steam Generation Plant	Scherer U4	31200	2.79%	-
050-STEAM ELEC EFFLUENT GUIDELI REV Total					**-**
054-COAL COMBUSTION RESIDUALS	02 - Steam Generation Plant	Scherer Comm	31100	1.51%	208,650
054-COAL COMBUSTION RESIDUALS	02 - Steam Generation Plant	Scherer Comm U3&4	31200	2.32%	18,764,434
054-COAL COMBUSTION RESIDUALS	02 - Steam Generation Plant	Scherer U4	31200	2.79%	93,124,003
054-COAL COMBUSTION RESIDUALS	02 - Steam Generation Plant	SJRPP - Comm	31100	1.09%	-
054-COAL COMBUSTION RESIDUALS Total					**112,097,087**
123-THE PROTECTED SPECIES PROJECT	05 - Other Generation Plant	CapeCanaveral U1CC	34300	2.96%	125,703
123-THE PROTECTED SPECIES PROJECT	05 - Other Generation Plant	FtMyers U2	34100	2.34%	-
123-THE PROTECTED SPECIES PROJECT Total					**125,703**
124 - Turkey Point Clean Water Recovery Center	05 - Other Generation Plant	Turkey Pt U5	34100	2.33%	-
124 - Turkey Point Clean Water Recovery Center Total					**-**
401-Air Quality Assurance Testing	01 - Intangible Plant	G:Intangible Plant	31670	14.29%	-
401-Air Quality Assurance Testing	02 - Steam Generation Plant	G:Crist Plant	31670	14.29%	83,954
401-Air Quality Assurance Testing Total					**83,954**
402-Crist 5, 6 & 7 Precipitator Projects	02 - Steam Generation Plant	CRIST PLANT - Common A	31400	4.00%	291,139
402-Crist 5, 6 & 7 Precipitator Projects	02 - Steam Generation Plant	CRIST PLANT - Unit 5	31200	4.00%	453,061
402-Crist 5, 6 & 7 Precipitator Projects	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31200	4.00%	7,646,441

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402-Crist 5, 6 & 7 Precipitator Projects	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31200	4.00%	147,682
402-Crist 5, 6 & 7 Precipitator Projects Total					**8,538,323**
403-Crist 7 Flue Gas Conditioning	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31200	4.00%	-
403-Crist 7 Flue Gas Conditioning Total					**-**
404-Low NOx Burners, Crist 6 & 7	02 - Steam Generation Plant	CRIST PLANT - Common A	31200	4.00%	131,183
404-Low NOx Burners, Crist 6 & 7	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31200	4.00%	2,902,903
404-Low NOx Burners, Crist 6 & 7	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31400	4.00%	11,338
404-Low NOx Burners, Crist 6 & 7	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31200	4.00%	5,516,349
404-Low NOx Burners, Crist 6 & 7	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31500	4.00%	44,385
404-Low NOx Burners, Crist 6 & 7	02 - Steam Generation Plant	G:Crist Plant	31670	14.29%	143,759
404-Low NOx Burners, Crist 6 & 7 Total					**8,749,918**
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	200,489
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	CRIST PLANT - Common A	31200	4.00%	3,282,349
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	CRIST PLANT - Unit 4	31200	4.00%	24,046
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	CRIST PLANT - Unit 5	31200	4.00%	20,502
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31200	4.00%	217,721
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31200	4.00%	341,530
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	DANIEL P-Com 1-2	31200	3.00%	356,393
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	DANIEL P-Com 1-2	31500	3.00%	196,553
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	DANIEL P-Com 1-2	31670	14.29%	3,097
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	DANIEL PLANT - Unit 1	31200	3.00%	32,584
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	DANIEL PLANT - Unit 2	31200	3.00%	37,519
405-CEMS - Plants Crist & Daniel Total					**4,712,783**
406-Substation Contamination Remediation	06 - Transmission Plant - Electric	G:Transmission Substations	35200	1.70%	339,156
406-Substation Contamination Remediation	06 - Transmission Plant - Electric	G:Transmission Substations	35300	2.80%	489,301
406-Substation Contamination Remediation	07 - Distribution Plant - Electric	G:Distribution	36100	1.90%	587,654
406-Substation Contamination Remediation	07 - Distribution Plant - Electric	G:Distribution	36200	3.10%	3,142,969
406-Substation Contamination Remediation Total					**4,559,079**
407-Raw Water Well Flowmeters Plants Crist & Smith	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	149,950
407-Raw Water Well Flowmeters Plants Crist & Smith	02 - Steam Generation Plant	CRIST PLANT - Common A	31200	4.00%	-
407-Raw Water Well Flowmeters Plants Crist & Smith	05 - Other Generation Plant	G:Smith Common - CT and C	34300	4.70%	-
407-Raw Water Well Flowmeters Plants Crist & Smith Total					**149,950**
408-Crist Cooling Tower Cell	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31200	4.00%	-
408-Crist Cooling Tower Cell Total					**-**
409-Crist Dechlorination System	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	76,079
409-Crist Dechlorination System	02 - Steam Generation Plant	CRIST PLANT - Common A	31400	4.00%	304,619
409-Crist Dechlorination System Total					**380,697**
410-Crist Diesel Fuel Oil Remediation	02 - Steam Generation Plant	CRIST PLANT - Common A	31200	4.00%	20,968
410-Crist Diesel Fuel Oil Remediation Total					**20,968**
411-Crist Bulk Tanker Unloading Second Containment	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	50,748
411-Crist Bulk Tanker Unloading Second Containment	02 - Steam Generation Plant	CRIST PLANT - Common A	31200	4.00%	-
411-Crist Bulk Tanker Unloading Second Containment Total					**50,748**
412-Crist IWW Sampling System	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	59,543
412-Crist IWW Sampling System Total					**59,543**
413-Sodium Injection System	02 - Steam Generation Plant	CRIST PLANT - Common A	31200	4.00%	-
413-Sodium Injection System Total					**-**
414-Smith Stormwater Collection System	05 - Other Generation Plant	G:Smith Common - CT and C	34100	4.70%	2,601,079
414-Smith Stormwater Collection System	05 - Other Generation Plant	G:Smith Common - CT and C	34500	4.70%	163,300
414-Smith Stormwater Collection System Total					**2,764,379**
415-Smith Waste Water Treatment Facility	05 - Other Generation Plant	G:Smith Common - CT and C	34100	4.70%	643,620
415-Smith Waste Water Treatment Facility Total					**643,620**
416-Daniel Ash Management Project	02 - Steam Generation Plant	DANIEL P-Com 1-2	31100	3.00%	7,157,673
416-Daniel Ash Management Project	02 - Steam Generation Plant	DANIEL P-Com 1-2	31200	3.00%	5,258,246
416-Daniel Ash Management Project	02 - Steam Generation Plant	DANIEL P-Com 1-4	31200	3.00%	1,633
416-Daniel Ash Management Project	02 - Steam Generation Plant	DANIEL P-Com 1-4	31670	14.29%	639
416-Daniel Ash Management Project	02 - Steam Generation Plant	DANIEL PLANT - Unit 1	31500	3.00%	2,521,370
416-Daniel Ash Management Project Total					**14,939,561**
417-Smith Water Conservation	05 - Other Generation Plant	G:Smith Common - CT and C	34100	4.70%	669,502
417-Smith Water Conservation	05 - Other Generation Plant	G:Smith Common - CT and C	34500	4.70%	2,059,084
417-Smith Water Conservation	05 - Other Generation Plant	G:Smith Unit 3 - Combined C	34100	4.70%	18,853,016
417-Smith Water Conservation	05 - Other Generation Plant	G:Smith Unit 3 - Combined C	34500	4.70%	9,159
417-Smith Water Conservation Total					**21,590,761**
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	1,285,488
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Common A	31200	4.00%	804,175
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Common A	31600	4.00%	143,514
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Unit 4	31200	4.00%	1,315,960
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Unit 5	31200	4.00%	1,314,974
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31100	4.00%	2
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31200	4.00%	7,412,213
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31500	4.00%	263,775
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31200	4.00%	17,627,439
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31500	4.00%	8,173,896
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31600	4.00%	181,043
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	G:Crist Plant	31670	14.29%	1,052,892
419-Crist FDEP Agreement for Ozone Attainment Total					**39,575,370**
420-SPCC Compliance	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	1,536,636
420-SPCC Compliance	05 - Other Generation Plant	G:Smith Common - CT and C	34100	4.70%	14,895
420-SPCC Compliance	08 - General Plant	G:General Plant	39400	14.29%	13,195
420-SPCC Compliance Total					**1,564,725**
421-Crist Common FTIR Monitor	02 - Steam Generation Plant	CRIST PLANT - Common A	31600	4.00%	-
421-Crist Common FTIR Monitor Total					**-**
422-Precipitator Upgrades for CAM Compliance	02 - Steam Generation Plant	CRIST PLANT - Unit 4	31200	4.00%	-
422-Precipitator Upgrades for CAM Compliance	02 - Steam Generation Plant	CRIST PLANT - Unit 5	31200	4.00%	-
422-Precipitator Upgrades for CAM Compliance Total					**-**
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	515,031
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Common A	31200	4.00%	1,474,422
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Common A	31400	4.00%	8,510,363
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Common A	31500	4.00%	2,544,385
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Common A	31600	4.00%	353,327
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Unit 4	31200	4.00%	190,220
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Unit 5	31200	4.00%	137,801
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31200	4.00%	374,984
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31400	4.00%	690,077
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31500	4.00%	39,519
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31200	4.00%	326,401
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31400	4.00%	-
424-Crist Water Conservation Total					**15,156,528**
425-Plant NPDES Permit Compliance Projects	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	325,432
425-Plant NPDES Permit Compliance Projects	02 - Steam Generation Plant	CRIST PLANT - Unit 4	31400	4.00%	1,579,996
425-Plant NPDES Permit Compliance Projects	02 - Steam Generation Plant	CRIST PLANT - Unit 5	31400	4.00%	1,773,231
425-Plant NPDES Permit Compliance Projects	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31200	4.00%	440,705
425-Plant NPDES Permit Compliance Projects	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31400	4.00%	5,827,708
425-Plant NPDES Permit Compliance Projects	02 - Steam Generation Plant	G:Crist Plant	31200	4.00%	77,326

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425-Plant NPDES Permit Compliance Projects	05 - Other Generation Plant	G:Smith Common - CT and C	34300	4.70%	3,798,266
425-Plant NPDES Permit Compliance Projects	05 - Other Generation Plant	G:Smith Common - CT and C	34400	4.70%	-
425-Plant NPDES Permit Compliance Projects Total					**13,822,664**
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	74,413,061
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Common A	31200	4.00%	28,460,790
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Common A	31400	4.00%	257,354
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Common A	31500	4.00%	68,740,170
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Common A	31600	4.00%	2,902,810
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Unit 4	31200	4.00%	4,624,344
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Unit 4	31500	4.00%	2,015,231
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Unit 5	31200	4.00%	5,644,235
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Unit 5	31500	4.00%	2,293,678
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31200	4.00%	48,940,398
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31500	4.00%	25,061,479
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31200	4.00%	17,061,678
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31400	4.00%	28,167,761
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31500	4.00%	2,126,229
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL P-Com 1-2	31100	3.00%	11,334,004
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL P-Com 1-2	31200	3.00%	210,391,868
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL P-Com 1-2	31500	3.00%	16,402,310
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL P-Com 1-2	31600	3.00%	334,923
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL P-Com 1-2	31650	20.00%	226,142
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL P-Com 1-2	31670	14.29%	383,892
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL PLANT - Unit 1	31100	3.00%	337,967
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL PLANT - Unit 1	31200	3.00%	94,886,018
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL PLANT - Unit 1	31500	3.00%	929,672
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL PLANT - Unit 1	31600	3.00%	151,046
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL PLANT - Unit 2	31100	3.00%	-
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL PLANT - Unit 2	31200	3.00%	40,480,081
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL PLANT - Unit 2	31600	3.00%	(22,658)
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL PLANT - Unit 2	31650	20.00%	-
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL PLANT - Unit 2	31670	14.29%	22,658
426-Air Quality Compliance Program	02 - Steam Generation Plant	G:Crist Plant	31100	4.00%	4,364,736
426-Air Quality Compliance Program	02 - Steam Generation Plant	G:Crist Plant	31200	4.00%	371
426-Air Quality Compliance Program	02 - Steam Generation Plant	G:Crist Plant	31500	4.00%	93,086
426-Air Quality Compliance Program	02 - Steam Generation Plant	G:Crist Plant	31670	14.29%	967,345
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-Common A	31100	2.20%	798,405
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-Common A	31200	2.20%	8,873,354
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-Common A	31500	2.20%	931,808
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-Common A	31670	14.29%	20,761
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-Common B	31100	2.20%	954,286
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-Common B	31200	2.20%	13,355,087
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-Common B	31500	2.20%	126,817
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-Common B	31600	2.20%	557
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-Common B	31670	14.29%	85,069
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-UNIT #3	31100	2.20%	7,386,372
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-UNIT #3	31200	2.20%	146,045,915
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-UNIT #3	31500	2.20%	5,888,098
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-UNIT #3	31600	2.20%	612
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-UNIT #3	31670	14.29%	19,404
426-Air Quality Compliance Program	05 - Other Generation Plant	G:Smith Plant CT	34200	6.30%	229,742
426-Air Quality Compliance Program	06 - Transmission Plant - Electric	G:Transmission 115-500KV L	35400	2.00%	565,268
426-Air Quality Compliance Program	06 - Transmission Plant - Electric	G:Transmission 115-500KV L	35500	4.60%	515,710
426-Air Quality Compliance Program	06 - Transmission Plant - Electric	G:Transmission 115-500KV L	35600	2.60%	562,755
426-Air Quality Compliance Program	06 - Transmission Plant - Electric	G:Transmission Substations	35200	1.70%	229,996
426-Air Quality Compliance Program	06 - Transmission Plant - Electric	G:Transmission Substations	35300	2.80%	4,198,658
426-Air Quality Compliance Program	08 - General Plant	G:General Plant	39780	5.20%	7,005
426-Air Quality Compliance Program Total					**882,788,356**
427-General Water Quality	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	996,766
427-General Water Quality Total					**996,766**
428-Coal Combustion Residuals	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	701,657
428-Coal Combustion Residuals	02 - Steam Generation Plant	DANIEL P-Com 1-2	31100	3.00%	16,859,368
428-Coal Combustion Residuals	02 - Steam Generation Plant	DANIEL P-Com 1-2	31200	3.00%	27,702
428-Coal Combustion Residuals	02 - Steam Generation Plant	DANIEL PLANT - Unit 1	31200	3.00%	9,994,211
428-Coal Combustion Residuals	02 - Steam Generation Plant	DANIEL PLANT - Unit 2	31200	3.00%	9,309,468
428-Coal Combustion Residuals	02 - Steam Generation Plant	G:Crist Plant	31100	0.00%	-
428-Coal Combustion Residuals	02 - Steam Generation Plant	G:Daniel Plant	31100	0.00%	-
428-Coal Combustion Residuals	02 - Steam Generation Plant	G:Scherer Plant	31100	0.00%	
428-Coal Combustion Residuals	02 - Steam Generation Plant	G:Daniel Plant	31100	3.00%	3,359,639
428-Coal Combustion Residuals	02 - Steam Generation Plant	G:Scholz Plant	31100	4.70%	-
428-Coal Combustion Residuals	02 - Steam Generation Plant	SCHERER PLANT-Common A	31200	2.20%	173,114
428-Coal Combustion Residuals	02 - Steam Generation Plant	SCHERER PLANT-Common B	31000	0.00%	773,371
428-Coal Combustion Residuals	02 - Steam Generation Plant	SCHERER PLANT-Common B	31100	2.20%	15,917,066
428-Coal Combustion Residuals	02 - Steam Generation Plant	SCHERER PLANT-Common B	31200	2.20%	9,954,406
428-Coal Combustion Residuals	02 - Steam Generation Plant	SCHERER PLANT-UNIT #3	31100	2.20%	525,049
428-Coal Combustion Residuals	02 - Steam Generation Plant	SCHERER PLANT-UNIT #3	31200	2.20%	6,464,769
428-Coal Combustion Residuals	05 - Other Generation Plant	G:Smith Common - CT and C	34100	4.70%	102,847,936
428-Coal Combustion Residuals	05 - Other Generation Plant	G:Smith Common - CT and C	34500	4.70%	1,027,022
428-Coal Combustion Residuals	05 - Other Generation Plant	G:Smith Common - CT and C	34600	4.70%	155,569
428-Coal Combustion Residuals	08 - General Plant	G:General Plant	39000	2.00%	-
428-Coal Combustion Residuals Total					**178,090,345**
429-Steam Electric Effluent Limitations Guidelines	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	5,657,885
429-Steam Electric Effluent Limitations Guidelines	02 - Steam Generation Plant	SCHERER PLANT-UNIT #3	31200	2.20%	385,147
429-Steam Electric Effluent Limitations Guidelines Total					**6,043,033**
430-316b Cooling Water Intake Structure Regulation	05 - Other Generation Plant	G:Smith Common - CT and C	34300	4.70%	3,907,009
430-316b Cooling Water Intake Structure Regulation Total					**3,907,009**
Grand Total					**2,803,195,309**

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Air Operating Permit Fees

Project No. 1

Combined Project

- **FPL Project 1 - Air Operating Permit Fees**
- **Gulf Project 2 - Air Emission Fees**

Project Description:

The Clean Air Act Amendments of 1990, Public Law 101-549, and Section 403.0872, Florida Statutes, require each major source of air pollution to pay an annual license fee. The amount of the fee is based on each source's previous year's emissions. The air operating permit fees cover units in Florida, as well as the Company's ownership share of Plant Scherer's Unit 3 and Unit 4 located in Juliette, Georgia. The fees for units in Florida are paid to the Florida Department of Environmental Protection ("FDEP") in the first quarter of each year. The Company pays its share of the fees for Scherer Unit 3 and Unit 4 to Georgia Power Company ("Georgia Power"), the operating agent, on a monthly basis for submittal to the Georgia Environmental Protection Division ("EPD"). Fees for Daniel Unit 1 and Unit 2 are paid on an annual basis to Mississippi Power Company.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

FPL O&M - Previous year's air operating permit fees for Florida facilities are calculated from final year ending generating unit emissions and Florida's Department of Environmental Protection ("FDEP") fees for each ton of regulated pollutant emitted. FPL submitted to the FDEP payment for the 2020 emissions following the first quarter of 2021. Permit fees for FPL's ownership share of Scherer Unit 4 were paid monthly in 2020 to Georgia Power for their submittal to the Georgia EPD in 2021 based on preliminary monthly emission data and trued-up when emission data was finalized. During the projection period FPL estimated permit fees for 2021 emissions based on projected unit operation and fuel use with current approved FDEP emission fees.

Gulf O&M - Previous year's air operating permit fees for Florida facilities are calculated from final year ending generating unit emissions and FDEP fees for each ton of regulated pollutant emitted. Gulf timely submitted to the FDEP payment for the prior year emissions. Permit fees for Gulf's ownership share of

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Scherer Unit 3 were paid to Georgia Power for their submittal to the Georgia EPD based on Unit 3 emission data. Title V operating permit fees for Gulf's ownership share of Daniel Units 1 and 2 were paid to Mississippi Power for their submittal to the Mississippi Department of Environmental Quality ("MDEQ") based on finalized emission data. During the projection period Gulf estimated permit fees for 2021 emissions based on projected unit operation and fuel use with the associated emission fees.

Project Costs:

(January 1, 2021 to December 31, 2021)

FPL O&M - Project expenditures are estimated to be $230,164, which is $45,450, or 24.6% higher than previously projected. The variance is primarily due to higher than originally projected gas and oil fuel usage, which resulted in increased permit fees paid in 2021 for unit operation in 2020. FPL pays permit fees based on the actual tons of pollutants emitted in the prior year. The annual Title V fee projection calculation is based on FPL fuel consumption projections and the FDEP's per ton fee for pollutant tons emitted.

Gulf O&M - Project costs are estimated to be $230,206, which is $49,024 or 17.6% lower than projected. The variance is primarily due to air emissions at the Gulf Clean Energy Center ("GCEC") (formerly Plant Crist) being less than originally projected due to the plant being off-line for approximately two months following Hurricane Sally and ceasing coal-fired operations in October 2020.

Project Projections:

(January 1, 2022 to December 31, 2022)

O&M - Estimated project costs for the projection period are $349,059.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Low NOx Burner Technology

Project No. 2

Combined Projects

- **FPL Project 2 - Low Nox Burner Technology**
- **Gulf Project 4 - Low Nox Burners, Crist 6 and 7**

Project Description:

Under Title I of the Clean Air Act Amendments of 1990, Public Law 101-349, utilities with units located in areas designated as "non-attainment" for ozone will be required to reduce Nitrogen Oxide ("NOx") emissions by implementing Reasonably Available Control Technology. To comply with the state's plan to bring the Dade, Broward and Palm Beach county areas into compliance with the ozone air quality standard, FPL implemented NOx burner technology on its oil and gas-fired steam generating units in those counties to reduce emissions of the pollutants that contributed to the ozone non-attainment. All affected units have been retired.

The GCEC Low NOx burners and associated equipment were installed to meet the requirements of the 1990 CAAA. The GCEC Low NO_x burner systems have proven effective in reducing NO_x emissions.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

FPL - No new activity scheduled for 2021.

Gulf - In January of 2021 portions of the GCEC Unit 6 and Unit 7 low NO_x burner systems were retired as part of converting GCEC from coal to gas-fired.

Project Costs:

(January 1, 2021 to December 31, 2021)

FPL Capital - Project revenue requirements are estimated to be $54,128, which is on target for 2021.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Gulf Capital - Project revenue requirements are estimated to be $1,494,596, which is $187,509 or 11.1% lower than previously projected. In January of 2021 portions of the GCEC Unit 6 and Unit 7 low NOx burner systems were retired as part of the gas conversion project.

Project Projections:

(January 1, 2022 to December 31, 2022)

Capital - Estimated project revenue requirements for the projection period are $1,730,423.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Continuous Emission Monitoring Systems ("CEMS")

Project No. 3

Combined Project

- **FPL Project 3 - Continuous Emission Monitoring Systems**
- **Gulf Project 5 - CEMS - Plant Crist and Daniel (Capital) and Emission Monitoring (O&M)**

Project Description:

The Clean Air Act Amendments of 1990, Public Law 101-549, established requirements for the monitoring, record keeping, and reporting of SO_2, NOx, and CO_2 emissions from affected air pollution sources. FPL's fossil-fired generating units are affected by these regulations and CEMS have been installed to comply with these requirements. Operation and maintenance of CEMS in accordance with the provisions of 40 CFR Part 75 is an ongoing activity performed according to the requirements of the FPL CEMS Quality Assurance ("QA") Program Manual approved by the Environmental Protection Agency ("EPA").

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

Operation, maintenance, and certification of the CEMS continues to be performed according to the requirements of the CEMS QA Program Manual, all applicable federal and state regulations, as well as local requirements. CEMS required parts are purchased as needed for repairs and/or preventative maintenance. CEMS analyzer calibration gases, that ensure accuracy of the measurements, are required to be used daily and are purchased as needed. FPL maintains its CEMS 24/7 Software Support contract with its CEMS vendor to ensure proper functionality as well as the integrity of the CEMS data. Training on the operation and maintenance of the system, as well as rule/regulation changes continue as needed.

Project Costs:

(January 1, 2021 to December 31, 2021)

FPL O&M - Project expenditures are estimated to be $366,961 which is on target for 2021.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Gulf O&M - Project expenditures are estimated to be $478,937, which is $158,057 or 24.8% lower than previously projected. The variance is due to reducing maintenance costs associated with the CEMS systems at Plant Smith and the GCEC by insourcing CEMS maintenance.

FPL Capital - Project revenue requirements are estimated to be $451,822, which is $6,810 or 1.53% higher than previously projected.

Gulf Capital - Project revenue requirements are estimated to be $513,894, which is on target for 2021.

Project Projections:

(January 1, 2022 to December 31, 2022)

O&M - Estimated project costs for the projection period are $1,135,028.

Capital - Estimated project revenue requirements for the projection period are $1,079,599.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Maintenance of Stationary Above Ground Fuel Storage Tanks

Project No. 5

Combined Project

- **FPL Project 5 - Maintenance of Stationary Above Ground Fuel Storage Tanks**
- **Gulf Project 12 - Aboveground Storage Tanks**

Project Description:

Florida Administrative Code ("F.A.C.") Chapter 62-762, provides standards for the maintenance of stationary above ground fuel storage tank systems and associated piping. These standards impose various implementation schedules for internal and external inspections, coating, repairs and upgrades to FPL's fuel storage tanks including secondary containment, spill containment, release detection, overfill protection (e.g., high level alarms, level gauges, etc.) and cathodic protection. Inspections and work performed on the fuel storage tanks and piping must follow certain standards such as the American Petroleum Institute ("API") standards. The project also requires equipment testing and includes registration fees that must be paid to the DEP for tanks that are in operation.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

FPL - Work continued on miscellaneous maintenance of above ground fuel storage tanks and piping systems. External inspections were completed for tanks at Manatee Plant, Fort Myers Plant and Port Everglades Plant. Touch-up coating work was completed on tanks at Turkey Point, Fort Myers Plant, and Manatee Terminal.

Gulf - The Pine Forest service center above ground fuel tank piping was replaced during 2021. Gulf will be completing hydrostatic tests on the secondary containment sumps for the service center underground piping and sump systems in 2021. Routine storage tank maintenance and inspections continued as required.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Costs:

(January 1, 2021 to December 31, 2021)

FPL O&M - Project expenditures are estimated to be $250,061, which is $142,141, or 36.2% lower than previously projected. The variance is primarily due to an error in forecasting maintenance costs for Port Everglades Tank #3 in clause recovery and subsequently determining that this tank is not recoverable through ECRC. This is partially offset by higher vendor quotes on Manatee Terminal Tank #1272 for painting and repairs, and lower than estimated costs for tank inspections and repairs at the Fort Myers site.

Gulf O&M - Project costs are estimated to be $264,476, which is $24,345 or 8.8% higher than previously projected.

FPL Capital - Project revenue requirements are estimated to be $1,604,019 which is $31,211 or 1.9% lower than previously projected.

Project Projections:

(January 1, 2022 to December 31, 2022)

O&M - Estimated project costs for the projection period are $283,901.

Capital - Estimated project revenue requirements for the projection period are $1,587,922.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Relocate Turbine Lube Oil Underground Piping to Above Ground

Project No. 7

Project Description:

In accordance with criteria contained in Chapter 62-762 F.A.C. for storage of pollutants, FPL replaced the underground turbine lube oil piping with above ground installations at the St. Lucie Nuclear Power Plant.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

There is no new activity scheduled in 2021.

Project Costs:

(January 1, 2021 to December 31, 2021)

FPL Capital - Project revenue requirements are estimated to be -$1,451, which is $2,859 or 203.07% lower than previously projected.

Project Projections:

(January 1, 2022 to December 31, 2022)

Capital - Estimated project revenue requirements for the projection period are $0.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Oil Spill Clean-up/Response Equipment

Project No. 8

Project Description:

The Oil Pollution Act of 1990 ("OPA 90") mandated that all regulated facilities that store or transfer oil over certain quantities and which reasonably could be expected to discharge oil into navigable waters prepare Facility Response Plans ("FRP") to address a worst case discharge of oil. The FRPs were required to be submitted to the appropriate agency (i.e., Coast Guard, EPA and DOT Pipeline & Hazardous Materials Administration) by August 18, 1993 or prior to going into operation. In these plans, a facility owner or operator must identify (among other items) its spill management team organization, response equipment and training, equipment inspection and exercise program. FPL developed plans for ten power plants, two fuel oil terminals, three pipelines, and one corporate plan. Additionally, FPL purchased the mandated response resources and provided for mobilization to a worst case discharge at each site.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

FRP updates continue to be performed for all sites as required. Routine maintenance and select replacement of remaining oil spill equipment has continued throughout the year. Training, as well as planned third quarter and fourth quarter oil spill drills, are pending subject to COVID-19 conditions.

Project Costs:

(January 1, 2021 to December 31, 2021)

FPL O&M - Project expenditures are estimated to be $267,940 which is on target for 2021.

Capital - Project revenue requirements are estimated to be $189,861 which is $18,224 or 8.76% lower than previously projected.

Project Projections:

(January 1, 2022 to December 31, 2022)

O&M - Estimated project costs for the projection period are $250,738.

Capital - Estimated project revenue requirements for the projection period are $191,639.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Relocate Storm Water Runoff

Project No. 10

Project Description:

The National Pollutant Discharge Elimination System ("NPDES") permit, Permit No. FL0002206 for the St. Lucie plant, issued by the EPA contains effluent discharge limitations for industrial-related storm water from the plant and land utilization building areas. The requirements became effective on January 1, 1994. As a result of these requirements, affected areas were surveyed, graded, excavated, and paved as necessary to clean and redirect the storm water runoff. The storm water runoff is collected and discharged to existing water catch basins on site.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

There is no new activity scheduled in 2021.

Project Costs:

(January 1, 2021 to December 31, 2021)

FPL Capital - Project revenue requirements are estimated to be $6,015, which is on target for 2021.

Project Projections:

(January 1, 2022 to December 31, 2022)

Capital - Estimated project revenue requirements for the projection period are $5,868.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Scherer Discharge Pipeline

Project No. 12

Project Description:

On March 16, 1992, pursuant to the provisions of the Georgia Water Control Act, as amended, the Federal Clean Water Act, as amended, and the rules and regulations promulgated thereunder, the Georgia Department of Natural Resources ("the Department") issued the NPDES permit for Plant Scherer to Georgia Power. In addition to the permit, the Department issued Administrative Order EPD-WQ-1855, which provided a schedule for compliance by April 1, 1994 with the facility discharge limitations to Berry Creek. As a result of these limitations, and pursuant to the order, Georgia Power was required to construct an alternate outfall to redirect certain wastewater discharges to the Ocmulgee River. Pursuant to the ownership agreement with Georgia Power for Scherer Unit 4, FPL is required to pay for its share of construction of the discharge pipeline, which will constitute the alternate outfall.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

There is no new activity scheduled in 2021.

Project Costs:

(January 1, 2021 to December 31, 2021)

FPL Capital - Project revenue requirements are estimated to be $32,591, which is on target for 2021.

Project Projections:

(January 1, 2022 to December 31, 2022)

Capital - Estimated project revenue requirements for the projection period are $26,821.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: NPDES Permit Fees

Project No. 14

Combined Project

- **FPL Project 14 - NPDES Permit Fees**
- **Gulf Project 8 - State NPDES Administration**

Project Description:

In compliance with Rule 62-4.052, F.A.C., FPL is required to pay annual regulatory program and surveillance fees for any NPDES permits which are required to allow the discharge of wastewater to surface waters. These fees implement the Florida Legislature's intent that the DEP's costs for administering the NPDES program be borne by the regulated parties, as applicable. Five-year permit renewal fees required for the NPDES industrial wastewater permits at the GCEC, Smith and Scholz are also included as required.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

The NPDES permit fees were paid to the FDEP for the seven applicable power generation and nuclear plants.

Project Costs:

(January 1, 2021 to December 31, 2021)

FPL O&M - Project costs are estimated to be $69,200 which is on target for 2021.

Gulf O&M- Project costs are estimated to be $41,150, which is $6,150 or 17.6% higher than previously projected.

Project Projections:

(January 1, 2022 to December 31, 2022)

O&M - Estimated project costs for the projection period are $103,700.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Oil-Filled Equipment and Hazardous Substance Remediation

Project 19

Combined Projects

- **FPL Projects 19a - Distribution and 19b. Transmission**
- **Gulf Project 6 - Substation Contamination Remediation and 7 - Groundwater Contamination Investigation**

Project Description:

Florida Statute Chapter 376 – Pollutant Discharge Prevention and Removal requires that any person discharging a pollutant, defined as any commodity made from oil or gas, shall immediately undertake to contain, remove and abate the discharge to the satisfaction of the DEP. This project includes the prevention and removal of pollutant discharges at FPL substations including equipment mineral oil and historical arsenic impacts.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

FPL O&M - Leak repair and regasketing work continues as needed on affected equipment identified during inspections. A mobile transformer has been utilized at one location to date to alleviate energy load problems in critical substations in order to repair and regasket leaking transformers. It is anticipated that three more mobile transformers may be required to be utilized in the remainder of 2021. The arsenic remediation work continues to be addressed at four substations where historical impacts have been identified.

Gulf O&M – The 2021 activities include preparing supplemental excavation addendums for Graceville and Pittman substations which will allow the Company to request a release from further remedial actions or No Further Action (“NFA”) with Conditions, from FDEP. A request for NFA with Conditions for the Sunny Hills site has been submitted and requests for Pittman and Destin are being prepared. Holmes Creek and Millers Ferry will follow upon completion of the previous submittals. Pending FDEP approval a NFA with Conditions packet will be submitted for Graceville.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Gulf Capital - During 2021, Gulf continued conducting a pilot test at the Wewa substation site to evaluate the feasibility of using chemical injection for groundwater remediation. The project is in the fourth quarter of the post-injection monitoring which will include an evaluation of the viability for full-scale implementation of this technology. If successful, the pilot test results will be used to design the full-scale implementation of this technology. If unsuccessful revised bench scale testing will resume.

Additionally, Gulf will be installing new cassette filters in the Beach Haven substation groundwater treatment system during late 2021. The filters need to be replaced to maintain compliance with the FDEP consent order in OGC file No. 88-0471. The replacement will extend the operation expectance of the system for an additional 5-8 years as remediation continues at this site.

Project Costs:
(January 1, 2021 to December 31, 2021)
FPL O&M - 19a. Project expenditures are estimated to be $3,371,911, which is $444,789, or 15.2% higher than projected. The variance is primarily due to the ability to obtain equipment clearances (i.e., de-energize equipment) required for equipment repair, which is resulting in a higher than projected number of transformers being repaired. FPL obtained additional equipment clearances by utilizing a mobile transformer.

FPL O&M - 19b. Project expenditures are estimated to be $1,347,095, which is $80,979 or 6.4% higher than previously projected.

Gulf O&M - Project expenditures are estimated to be $2,182,778 which is on target for 2021.

Gulf Capital - Project expenditures are estimated to be $434,535, which is $25,094 or 5.5% lower than previously projected.

Project Projections:
(January 1, 2022 to December 31, 2022)
O&M - Estimated project costs for the projection period are $6,494,265.

Capital - Estimated project revenue requirements for the projection period are $539,741.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Wastewater Discharge Elimination & Reuse

Project No. 20

Project Description:

Pursuant to 33 U.S.C. Section 1342 and 40 CFR 122, FPL is required to obtain NPDES permits for each power plant facility. The last permits issued contain requirements to develop and implement a Best Management Practice Pollution Prevention Plan (BMP3 Plan) to minimize or eliminate, whenever feasible, the discharge of regulated pollutants, including fuel oil and ash, to surface waters. In addition, the DEP Industrial Wastewater Permits issued under 62-620 F.A.C., regulate discharges of any wastewater discharges to groundwater at all plants, and the Miami-Dade County Department of Environmental Resource Management requires the Turkey Point plant's wastewater discharges into canals to meet county water quality standards found in Section 24-42, Code of Miami-Dade County. In order to address these requirements, FPL has undertaken a multifaceted project, which includes activities such as ash basin lining, installation of retention tanks, tank coating, sump construction, installation of pumps, motor, and piping, boiler blowdown recovery, site preparation, separation of stormwater and ashwater systems, separation of potable and service water systems, and the associated engineering and design work to implement these projects.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

There is no new activity scheduled in 2021.

Project Costs:

(January 1, 2021 to December 31, 2021)

FPL Capital - Project revenue requirements are estimated to be $42,559, which is on target for 2021.

Project Projections:

(January 1, 2022 to December 31, 2022)

Capital - Estimated project revenue requirements for the projection period are $68,935.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: St. Lucie Turtle Net

Project No. 21

Project Description:

The Incidental Take Statement contained in the Endangered Species Act Section 7 Consultation Biological Opinion, issued to FPL on March 24, 2016, by the National Marine Fisheries Service limits the number of lethal turtle “takings” permitted at its St. Lucie Power Plant. An effective 5-inch primary barrier net is vital to limiting the number of lethal turtle takes per year.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

Inspections and cleaning were performed to remove algae and jellyfish buildup that occurred on the turtle net.

Project Costs:

(January 1, 2021 to December 31, 2021)

FPL O&M - Project expenditures are estimated to be $329,195, which is $39,205 or 10.6% lower than previously projected.

FPL Capital - Project revenue requirements are estimated to be $724,354, which is on target for 2021.

Project Projections:

(January 1, 2022 to December 31, 2022)

O&M - Estimated project costs for the projection period are $368,400.

Capital - Estimated project revenue requirements for the projection period are $723,372.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Pipeline Integrity Management Program

Project No. 22

Project Description:

FPL is required to develop and implement a written pipeline integrity management program for its hazardous liquid/gas pipelines. This program must include the following elements: (1) a process for identifying which pipeline segments could affect a high consequence area; (2) a baseline assessment plan; (3) an information analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure; (4) the criteria for determining remedial actions to address integrity issues raised by the assessments and information analysis; (5) a continual process of assessment and evaluation of pipeline integrity; (6) the identification of preventive and mitigative measures to protect the high consequence area; (7) the methods to measure the program's effectiveness; (8) a process for review of assessment results and information analysis by a person qualified to evaluate the results and information; and (9) record keeping.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)
Cathodic protection surveys were completed for the Manatee Fuel Terminal in Q2 2021.

Project Costs:

(January 1, 2021 to December 31, 2021)
FPL O&M - Project expenditures are -$2, which is $77,502, or 100% lower than previously projected. The decrease is a result of no findings noted in the 2020 inspection that needed attention in 2021. No post-inspection confirmatory digs were required from the 2020 inspection report.

FPL Capital - Project revenue requirements are estimated to be $257,955, which is on target for 2021.

Project Projections:

(January 1, 2022 to December 31, 2022)
O&M - Estimated project costs for the projection period are $0.

Capital - Estimated project revenue requirements for the projection period are $258,287.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Spill Prevention, Control, and Countermeasures ("SPCC") Program

Project No. 23

Combined Projects

- **FPL Project 23 - Spill Prevention, Control, and Countermeasures Program**
- **Gulf Project 11 - Crist Bulk Tanker Unloading Secondary Containment and 20 - SPCC Compliance. Includes SPCC costs from General Solid & Hazardous Waste Project, Gulf Project 11 in 2022**

Project Description:

The EPA issued the Oil Pollution Prevention Regulation (i.e., SPCC rule) to address the oil spill prevention provisions contained in the Federal Water Pollution Control Act of 1972 (later amended as the Clean Water Act) to prevent discharges of oil from reaching the navigable waters of the United States. The SPCC rule also requires certain facilities to prepare and implement SPCC Plans and address oil spill prevention requirements including the establishment of procedures, methods, equipment, and other requirements to prevent discharges of oil as described above. As revised, the SPCC rule requires that each regulated facility prepare and implement an SPCC Plan; install secondary containment and/or diversionary structures for bulk oil storage containers, certain oil-filled equipment, piping and tank truck unloading racks/areas; provide overfill protection (e.g., tank level alarms, etc.); and conduct training, inspections, testing, security measures and facility drainage systems.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

FPL and Gulf routinely review and update the FRP and SPCC Plans for their power plants and the FPL fuel terminal facilities. These updates incorporate modifications to tanks, piping, equipment, transformers, containment features and drainage systems as well as enhancements to facility inspection programs.

FPL - Fort Myers continues installation of the permanent boom across the discharge canal, which is estimated to be completed in the second half of 2021. In addition, Martin completed the installation of the permanent slide gates at the Martin Land Utilization to boom the canal in the event of an emergency.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Gulf - A new oil SPCC plan was developed for the GCEC in June of 2021 in accordance with the Federal regulation (Title 40, Code of Federal Regulation Part 112). The plan requires installation of permanent oil containment in the 2022-2023 timeframe to capture potential oil spills and prevent oil from reaching surface waters. Engineering and design of the permanent boom installation is currently scheduled for the second half of 2021 in order to begin construction in early 2022.

Project Costs:

(January 1, 2021 to December 31, 2021)

FPL O&M - Project costs are estimated to be $748,442, which is $78,226 or 9.5% lower than previously projected.

Gulf O&M - Gulf's SPCC O&M costs are included under the General Solid and Hazardous Waste (Previously Project 11 line item for 2021).

FPL Capital - Project revenue requirements are estimated to be $2,185,488, which is $69,777 or 3.1% lower than previously projected.

Gulf Capital

11 - Crist Bulk Tanker Unload Secondary Containment Structure – Project revenue requirements are estimated to be $2,624, which is on target for 2021.

20 - SPCC Compliance – Project revenue requirements are estimated to be $71,794, which is on target for 2021.

Project Projections:

(January 1, 2022 to December 31, 2022)

O&M - Estimated project costs for the projection period are $860,757.

Capital - Estimated project revenue requirements for the projection period are $2,381,296.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Manatee Plant Reburn

Project No. 24

Project Description:

This project involves installation of reburn technology in Manatee Units 1 and 2 to provide significant reductions in NOx emissions from Manatee Units 1 and 2 to reduce impacts to local ozone air quality impacts that the DEP had required FPL to achieve. FPL determined that reburn technology was the most cost-effective alternative to achieve significant reductions in NOx emissions. Reburn is an advanced NOx control technology that has been developed for, and applied successfully in, commercial applications to utility and large industrial boilers to reduce emissions that do not require the use of reagents, catalysts, and pollution reduction or removal equipment.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

There is no new activity currently scheduled in 2021

Project Costs:

(January 1, 2021 to December 31, 2021)

FPL O&M - Project expenditures are estimated to be $3,471, which is $208,861, or 98.4% lower than previously projected. The decrease is primarily due to the anticipated dismantlement of Manatee Units 1&2 and the determination that scheduled inspections on the reburn systems are no longer needed.

Capital - Project revenue requirements are estimated to be $2,861,685, which is on target for 2021.

Project Projections:

(January 1, 2022 to December 31, 2022)

O&M - Estimated project costs for the projection period are $0.

Capital - Estimated project revenue requirements for the projection period are $2,049,056.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Underground Storage Tank ("UST") Replacement/Removal

Project No. 26

Project Description:

Chapter 62-761.500 of the F.A.C., dated July 13, 1998, requires the removal or replacement of existing Category-A and Category-B storage tank systems with systems meeting the standards of Category-C storage tank systems by December 31, 2009. UST Category-A tanks are single-walled tanks or underground single-walled piping with no secondary containment that were installed before June 30, 1992.

UST Category-B tanks are tanks containing pollutants after June 30, 1992 or a hazardous substance after January 1, 1994 that shall have secondary containment. Small diameter piping that comes in contact with the soil that is connected to a UST shall have secondary containment if installed after December 10, 1990.

UST and AST Category-C tanks under F.A.C. 62-761.500 are tanks that shall have some or all of the following; a double wall, be made of fiberglass, exterior coatings that protect the tank from external corrosion, secondary containment (e.g., concrete walls and floor) for the tank and the piping, and overfill protection.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)
There is no new activity scheduled in 2021.

Project Costs:

(January 1, 2021 to December 31, 2021)
FPL Capital - Project revenue requirements are estimated to be $6,530, on target for 2021.

Project Projections:

(January 1, 2022 to December 31, 2022)
Capital - Estimated project revenue requirements for the projection period are $6,487.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Lowest Quality Water Source ("LQWS")

Project No. 27

Combined Projects

- **FPL Project 27 - Lowest Quality Water Source**
- **Gulf Project 7 - Raw Water Well Flowmeters, Projects 17 - and 24 - Smith Water Conservation, and Project 22 and Project 24 - Crist Water Conservation**

Project Description:

The LQWS Project is required in order to comply with permit conditions in the Consumptive Use Permits ("CUP") issued by the St. Johns River Water Management District ("SJRWMD" or "the District") for the Sanford Plant and the Northwest Florida Management District ("NWFWMD") for Plant Smith and GCEC. Those permit conditions are intended to preserve Florida's groundwater, which is an important environmental resource.

The SJRWMD adopted a policy in 2000 that, upon permit renewal, a user of the District's water is required to use the lowest quality of water that is technically, environmentally and economically feasible for its needs. In 2000, the SJRWMD issued a CUP which required use of water from the Sanford Cooling Pond as the LQWS. In 2021, the SJRWMD renewed the CUP and is now requiring all groundwater use at the site be replaced with surface water.

Specific Condition 11 of Plant Smith's consumptive use permit requires the plant to implement measures to increase water conservation and efficiency at the facility. Phase I of the Smith Water Conservation project consisted of adding pumps, piping, valves, and controls to reclaim water from the ash pond. During Phase II of the project, the Smith closed loop cooling for the laboratory sampling system was installed to further reduce groundwater usage. Phase III of the project includes investigating and installing a deep injection well system to allow Plant Smith to utilize reclaimed water.

The goal of the GCEC water conservation and consumptive use efficiency project is to reduce the demand for groundwater and surface water withdrawals. Specific Condition 19 of GCEC's consumptive use permit requires the plant to implement measures to increase water conservation and efficiency at the facility. The first GCEC water conservation project included installing automatic level controls on the fire water tanks in order to reduce groundwater usage. The second phase of the project involved utilizing reclaimed water to reduce the demand for groundwater and surface water withdrawals at the facility. The GCEC began receiving reclaimed water in November 2010. The GCEC also installed defoaming and acid injection systems for the Unit 6 and 7 cooling towers in order to treat scaling and foam associated with reclaimed water usage.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

In 2020, the Sanford Plant submitted a renewal application for its CUP #9202. The final permit was approved by the SJRWMD Governing Board and issued on July 13th, 2021. This renewed CUP requires the Sanford Plant to relinquish the site's groundwater allocation and replace it with St. Johns river water, in accordance with the LQWS requirement. This new permit condition will require new equipment and system modifications in order to connect the St. Johns River source water to the existing water treatment system.

During 2021 Gulf is continuing to evaluate project design, technical specifications and cost, and is in negotiations with Bay County. If determined prudent,. construction of the new reclaimed water treatment system and permanent pump station would begin in 2022. Both projects will be required before the plant can begin using reclaimed water for the Unit 3 cooling tower water supply. The GCEC is installing new chemical tanks for the reclaimed water treatment system in 2021.

Maintenance and compliance monitoring are ongoing as required.

Project Costs:

(January 1, 2021 to December 31, 2021)

FPL O&M - Project expenditures are estimated to be $105,036, which is $3,036 or 2.98% higher than previously projected.

Gulf O&M

22 - Crist Water Conservation – Project expenditures are estimated to be $239,450, which is $19,253 or 7.4% lower than previously projected.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

24 - Smith Water Conservation – Project expenditures are estimated to be $99,765, which is $22,735 or 18.6% lower than previously projected.

Gulf Capital
7 - Raw Water Flow Meters - Project revenue requirements are estimated to be $12,141, which is on target for 2021.

17 - Smith Water Conservation –Project revenue requirements are estimated to be $2,255,150, which is $408,426 or 15.3% lower than previously projected. The variance is primarily due to postponing construction of the Plant Smith Underground Injection Control (“UIC”) wastewater treatment system and associated pump station from 2021 to 2022 due to additional time required to finalize design of the onsite reclaimed water distribution system and to complete additional geotechnical investigations for the reclaimed water supply pipeline between Bay County’s North Bay Water Treatment Plant and Plant Smith. Additional delay is due to pending contract negotiations between the County and Gulf.

24 - Crist Water Conservation – Project revenue requirements are estimated to be $1,479,666, which is on target for 2021.

Project Projections:
(January 1, 2022 to December 31, 2022)
O&M - Estimated project costs for the projection period are $213,500.

Capital - Estimated project revenue requirements for the projection period are $5,192,904.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: CWA 316(b) Phase II Rule

Project No: 28

Combined Projects

- **FPL Project 28 - CWA 316(b) Phase II Rule**
- **Gulf Project 30 - 316(b) Cooling Water Intake Structure Regulation. Includes 316(b) O&M expenses from Project 427 - General Water Quality in 2022**

Project Description:

The final rule entitled, "National Pollutant Discharge Elimination System - Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities" (the 316(b) Rule and formerly the CWA 316(b) Phase II Rule) became effective October 14, 2014. and is found in 40 CFR Parts 122 and 125 which implements section 316(b) of the Clean Water Act ("CWA") for existing power plants. The 316(b) Rule is applicable to all power plants and other manufacturing that employ a cooling water intake structure and that withdraw two million gallons per day or more of water from rivers, streams, lakes, reservoirs, estuaries, oceans or other Waters of the United States for cooling purposes. The 316(b) Rule established national requirements applicable to, and that reflect, the best technology available ("BTA") for the location, design, construction and capacity of existing cooling water intake structures to minimize adverse environmental impacts. The DEP adopted the 316(b) Rule on June 24, 2015 and is implementing it at the following FPL facilities: Cape Canaveral Energy Center ("CCEC"), Ft. Myers Plant ("PFM"), Dania Beach Energy Center ("DBEC", former Lauderdale Plant), Port Everglades Energy Center ("PEEC"), Riviera Beach Energy Center ("RBEC"), Sanford Plant ("PSN"), Martin Plant ("PMR"), Manatee Plant ("PMT"), St. Lucie Plant ("PSL"), Gulf Clean Energy Center ("GCEC"), and Plant Smith. Plant Scherer is also regulated by the 316(b) Rule through the Georgia Environmental Protection Division.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

FPL - In 2021, work was conducted by consultants on reports required by the 316(b) Rule to determine the appropriate BTA for minimizing impingement mortality and entrainment at all of FPL's facilities employing once-through cooling water systems. This work will continue through the 2023 timeframe.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Gulf - New lower capacity intake pumps and associated equipment have been placed in-service at Plant Smith.

Project Costs:

(January 1, 2021 to December 31, 2021)

FPL O&M - Project expenditures are estimated to be $397,890, which is $106,327, or 21.1% lower than previously projected. The decrease is primarily due to the delayed renewal of the Industrial Wastewater ("IWW") Permit for the Port Everglades Energy Center ("PEEC"). PEEC was projected to begin a two-year Impingement Optimization Study ("IOS") during calendar year 2021. However, the renewed IWW permit was not issued during the second quarter of 2021 as anticipated, thereby delaying the study. FPL anticipates the renewed IWW permit will be issued in the end of 2021/early 2022 and will contain the requirement to complete the IOS.

Gulf O&M - The 2021 316(b) O&M expenses for Gulf are included under the General Water Quality project.

FPL Capital - Project revenue requirements are estimated to be $76,351, which is on target for 2021.

Gulf Capital - Project revenue requirements are estimated to be $399,859, which is $93,761 or 19.0% lower than previously projected. The variance is due to cost of removal for the Plant Smith 316(b) intake pump project being inadvertently included in the original projections for the new project additions in 2020 and 2021. The actual cost of removal was booked correctly to a non ECRC account, resulting in a lower ECRC plant in-service balance in 2021.

Project Projections:

(January 1, 2022 to December 31, 2022)

O&M - Estimated project costs for the projection period are $244,064.

Capital – Estimated project revenue requirements for the projection period are $567,623.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: St. Lucie Cooling Water System Inspection and Maintenance

Project No. 34

Project Description:

The purpose of the proposed St. Lucie Plant Cooling Water System Inspection and Maintenance Project is to inspect and, as necessary, maintain the cooling water system (the "Cooling System") at FPL's St. Lucie Nuclear Power Plant, such that it minimizes injuries and/or deaths of endangered species and thus helps FPL to remain in compliance with the Federal Endangered Species Act, 16 U.S.C. Section 1531, et seq. The specific "environmental law or regulation" requiring inspection and cleaning of the intake pipes are terms and conditions imposed pursuant to a Biological Opinion ("BO") that was issued by the National Marine Fisheries Service ("NMFS") pursuant to Section 7 of the Endangered Species Act. The NMFS finalized the BO on March 24, 2016. FPL is currently working with NMFS to develop an acceptable cooling system turtle excluder device or alternatives, as required by the BO.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

The project is currently on hold while the NMFS is developing an updated BO.

Project Costs:

(January 1, 2021 to December 31, 2021)

FPL Capital - Project revenue requirements are estimated to be $356,179, which is on target for 2021.

Project Projections:

(January 1, 2022 to December 31, 2022)

Capital - Estimated project revenue requirements for the projection period are $404,389.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Martin Plant Water System

Project No. 35

Project Description:

The Martin Plant Drinking Water System is required to comply with the requirements of the DEP's rules for drinking water systems. The DEP determined the system must be brought into compliance with newly imposed drinking water rules for trihalomethanes and Haleo Acetic Acid. These include nano-filtration, air stripping, carbon and multimedia filtration.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

Martin completed the conversion to the Village of Indiantown as the supplier of the potable water for the entire site.

Project Costs:

(January 1, 2021 to December 31, 2021)

Capital - Project revenue requirements are estimated to be $14,167, which is $5,640 or 28.47% lower than previously projected.

Project Projections:

(January 1, 2022 to December 31, 2022)

Capital - Estimated project revenue requirements for the projection period are $22,948.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Low Level Radioactive Waste

Project No. 36

Project Description:

The Barnwell, South Carolina radioactive waste disposal facility is the only site of its kind presently available to FPL for disposal of Low Level Waste ("LLW") such as radioactive spent resins, filters, activated metals, and other highly contaminated materials. On June 30, 2008, the Barnwell facility ceased accepting LLW from FPL. The objective of this project is to provide a LLW storage facility at the St. Lucie and Turkey Point plants with sufficient capacity to store all LLW B and C class waste generated at each plant site over a 5-year period. This will allow continued uninterrupted operation of the St. Lucie and Turkey Point nuclear units until an alternate solution becomes available. The LLW on site storage facilities at St. Lucie and Turkey Point also provide a "buffer" storage capacity for LLW even if an alternate solution becomes feasible, should the alternate solution be delayed or interrupted at a later date.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

There is no new activity scheduled in 2021.

Project Costs:

(January 1, 2021 to December 31, 2021)

Capital - Project revenue requirements are estimated to be $1,618,894, which is on target for 2021.

Project Projections:

(January 1, 2022 to December 31, 2022)

Capital - Estimated project revenue requirements for the projection period are $1,603,192.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: DeSoto Next Generation Solar Energy Center

Project No. 37

Project Description:

The DeSoto Next Generation Solar Energy Center ("DeSoto Solar") project is a zero greenhouse gas emitting renewable generation project, which, on August 4, 2008, the Commission found in Order Number PSC-08-0491-PAA-EI, to be eligible for recovery through the ECRC pursuant to House Bill 7135. The DeSoto Solar project is a 25 MW solar photovoltaic ("PV") generating facility, which converts sunlight directly into electric power utilizing tracking arrays that are designed to follow the sun as it traverses through the sky. In addition, the system includes electrical equipment necessary to convert the power from direct current to alternating current to connect the system to the FPL grid. Ongoing operation and maintenance expenses include repair and replacement of PV system components and support equipment and facilities by FPL personnel and vegetation management of land adjacent to the panels.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

Several direct current field walk downs and necessary repairs were performed this year, in order to ensure improved efficiency to current performance. Preventative maintenance work including inverter cleanings, inverter condition assessments, and switchgear maintenance was performed according to site prescribed maintenance cycle. Site personnel continue to perform required maintenance activities including replacement of components as necessary. As of August 2021, Site personnel continue to perform required maintenance activities including replacement of components as necessary. Delays have occurred due to material orders and other priorities.

Project Costs:

(January 1, 2021 to December 31, 2021)

FPL O&M - Project expenditures are estimated to be $388,452, which is $157,834, or 28.9% lower than previously projected. The variance is primarily due to less full-time employee support required to maintain the DeSoto site than originally projected. Additionally, planned contractor services for the combiner boxes and tracker assemblies were deemed to be capital work in nature and removed from the O&M forecast.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Capital - Project revenue requirements are estimated to be $11,422,133, which is on target for 2021.

Project Projections:

(January 1, 2022 to December 31, 2022)

O&M - Estimated project costs for the projection period are $505,094.

Capital - Estimated project revenue requirements for the projection period are $11,059,540.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Space Coast Next Generation Solar Energy Center

Project No. 38

Project Description:

The Space Coast Next Generation Solar Energy Center ("Space Coast Solar") project is a zero greenhouse gas emitting renewable generation project, which on August 4, 2008, the Commission found in Order Number PSC-08-0491-PAA-EI, to be eligible for recovery through the ECRC pursuant to House Bill 7135. The Space Coast Solar project is a 10 MW PV generating facility which converts sunlight directly into electric power. The facility utilizes a fixed array and uses solar PV panels, support structures, and electrical equipment necessary to convert the power from direct current to alternating current and to connect the system to the FPL grid. Ongoing operation and maintenance expenses include repair and replacement of PV system components and support equipment and facilities by FPL personnel and vegetation management of land adjacent to the panels.

The Space Coast project also included building a 900 kW solar PV facility at the Kennedy Space Center ("KSC") industrial area. The KSC solar site was built and is operated and maintained by FPL as compensation for the lease of the land for the Space Coast Solar site which is located on KSC property.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

Quarterly O&M reports are submitted to NASA in accordance with the lease agreement between NASA and FPL. Support personnel continue to perform required maintenance activities including replacement of components as necessary for Space Coast/Kennedy Solar ECRC sites.

Project Costs:

(January 1, 2021 to December 31, 2021)

FPL O&M - Project expenditures are estimated to be $259,673, which is $8,433 or 3.2% lower than previously projected.

FPL Capital - Project revenue requirements are estimated to be $5,325,746, which
on target for 2021.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Projections:

(January 1, 2022 to December 31, 2022)

O&M - Estimated project costs for the projection period are $283,499.

Capital - Estimated project revenue requirements for the projection period are $5,154,426.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Martin Next Generation Solar Energy Center (Solar Thermal)

Project No. 39

Project Description:

On August 4, 2008, the Commission found, in Order Number PSC-08-0491-PAA-EI, that the Martin Next Generation Solar Energy Center ("Martin Solar") project was eligible for recovery through the ECRC pursuant to House Bill 7135. The Martin Solar project is a 75 MW solar thermal steam generating facility which is integrated into the existing steam cycle for the Martin Unit 8 natural gas-fired combined cycle power plant. The steam supplied by Martin Solar is used to supplement the steam currently generated by the heat recovery steam generators. The project involved the installation of parabolic trough solar collectors that concentrate solar radiation on heat collection elements and track the sun to maintain the optimum angle to collect solar radiation. These heat collection elements contain a heat transfer fluid ("HTF") that is heated by the concentrated solar radiation and is then circulated to heat exchangers that will produce steam, which is routed to the existing Martin Unit 8 heat recovery steam generators for use in generating a design rating of 75 MW of electricity from the Martin Unit 8 Steam Turbine Generator.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

2021 to date, Martin Solar accomplishments include routine repairs to solar loops, including replacement of heat collection elements and parabolic mirrors, oil changes on the solar array hydraulic drives, and 10-year vessel integrity inspections on solar heat exchangers. Other accomplishments include the installation of high temperature flowmeters on several heat collection loops that provide data for maintaining high efficiency, various preventative maintenance jobs completed in the solar field and power block and use of drone thermography to perform field inspections.

Project Costs:

(January 1, 2021 to December 31, 2021)

FPL O&M - Project costs are estimated to be $4,051,443 which is on target for 2021.

FPL Capital - Project revenue requirements are estimated to be $32,972,967 which is on target for 2021.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Projections:

(January 1, 2022 to December 31, 2022)

O&M - Estimated project costs for the projection period are $4,272,772.

Capital - Estimated project revenue requirements for the projection period are $32,352,118.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Greenhouse Gas Reduction Program

Project No. 40

Project Description:

The purpose of FPL's Electric Utility Greenhouse Gas ("GHG") Reduction Program is to comply with the EPA's policies that require reductions in emissions of GHGs from electric generating units and mandatory reporting of GHG emissions. The EPA's Mandatory GHG Reporting Rule requires electric utilities to record emissions of GHGs, primarily CO_2 from the combustion of fossil fuels, and report actual data in the subsequent year. FPL was required to begin reporting GHGs emitted from its fossil generating units annually starting in 2011 for calendar year 2010 and to report every year thereafter. The EPA's performance standards for reductions of GHG emissions have been proposed as a final rule that addresses only efficiency improvements on coal-fired electric utility steam generating units. While the proposed rule has been challenged, FPL does not currently anticipate any additional costs for compliance with the new GHG rule.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

There is no new activity scheduled in 2021.

Project Costs:

(January 1, 2021 to December 31, 2021)

FPL O&M - Project costs are estimated to be $0.

Project Projections:

(January 1, 2022 to December 31, 2022)

O&M - There are no projected costs.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Manatee Temporary Heating System ("MTHS")

Project No. 41

Project Description:

FPL is subject to specific and continuing legal requirements to provide warm water refuges for the threatened manatee at its Port Everglades, Ft. Myers, Lauderdale, Riviera, and Cape Canaveral plants.

FPL's installation of a MTHS at each site was implemented to provide warm water until each site completed the planned modernization of the existing power generation units and the warm water flow from the generating unit cooling water returned. The Power Plant Siting Act Conditions of Certification ("COCs") require additional environmental and biological monitoring associated with the operation of the heaters during and following plant shut-downs due to the modernizations. The modernization projects have been completed at Cape Canaveral ("CCEC"), Port Everglades ("PEEC") and Riviera ("RBEC"), with Fort Lauderdale being modernized ("Dania Beach Clean Energy Center"-DBEC) during the 2018-2022 time frame. For Cape Canaveral, the heating system remained in place to serve as an emergency backup in the future in case the entire Unit 3 power block needs to shut down during future manatee seasons. Due to requirements of the U.S. Fish and Wildlife Service ("USFWS") to reduce the possibility of impinging dead or severely compromised manatees on the Cape Canaveral intake screens, Cape Canaveral relocated the permanent manatee heating area farther from the plant intakes. Fort Myers is also installing a permanent MTHS due to its "northern" location and the probability of reduced plant operation in the future.

Per the COCs for CCEC, RBEC, PEEC and DBEC, once the USFWS and Florida Fish & Wildlife Conservation Commission ("FWC") complete their Warm Water Action Plan ("WWAP"), FPL is required to host a workshop for the development of a long-term manatee strategy. The WWAP was completed in 2020 and FPL plans to host the workshop in the second quarter of 2022. After the workshop, FPL is also required to submit a summary report of actionable items to be put in to place to meet the goals of the WWAP and workshop.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

The MTHS at the Lauderdale Plant (Dania Beach Energy Center) and Fort Myers Plant are installed and will run as needed during manatee seasons.

Project Costs:

(January 1, 2021 to December 31, 2021)

FPL O&M - Project costs are estimated to be $162,330, which is $33,570 or 17.14% lower than previously projected. The variance is primarily due to lower than projected costs related to required monitoring at the Dania Beach Energy Center.

FPL Capital - Project revenue requirements are estimated to be $3,154,746, which is on target for 2021.

Project Projections:

(January 1, 2022 to December 31, 2022)

O&M - Estimated project costs for the projection period are $1,201,800.

Capital - Estimated project revenue requirements for the projection period are $2,978,826.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Turkey Point Cooling Canal Monitoring Plan ("TPCCMP")

Project No. 42

Project Description:

Pursuant to Conditions IX and X of the DEP's Final Order Approving Site Certification, FPL submitted a revised Cooling Canal Monitoring Plan ("Revised Plan") to the South Florida Water Management District ("SFWMD"). After receiving input from the SFWMD as well as the DEP and Miami-Dade County Department of Environmental Resource Management ("MDC DERM"), the Revised Plan was finalized on October 14, 2009. The objective of FPL's TPCCMP Project is to implement the Conditions of Certification IX and X.

Based on the data FPL had collected pursuant to the Revised Plan, in October 2015, the MDC DERM entered into a Consent Agreement ("CA") with FPL. On April 25, 2016, FDEP issued a Notice of Violation ("NOV") regarding the hypersaline groundwater to the west of the CCS and a Warning letter identifying issues related to water quality in a few deep artificial channels to the east and south of the CCS. The NOV directed FPL to enter into a Consent Order ("CO") to, at a minimum, remediate the CCS contribution to the hypersaline plume, reduce the size of the hypersaline plume, and prevent future harm to waters of the State. The CO was executed between FPL and the DEP on June 20, 2016.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

FPL continues to move forward with compliance and implementation of actions required under the CO, CA and CAA. FPL has continued operation of the recovery well system ("RWS") consisting of 10 extraction wells required by the CO and CA. The RWS extracts up to 15 million gallons per day of hypersaline groundwater from the Biscayne aquifer and safely disposes it in an underground injection control ("UIC") well. After 2.5 years of operations, the RWS reduced the hypersaline plume volume by 34% based on the results of the Continuous Surface Electromagnetic Mapping survey. The results indicate the RWS is functioning as designed and is on track to achieve the objectives outlined in the CO. FPL also continued implementing strategies under the Nutrient Management Plan required by the CO to reduce nutrients in the CCS surface waters. FPL continues to implement an extensive vegetation management plan to remove exotic vegetation from the canal berms, which is a source of nutrients in the CCS. These efforts will assist in reducing nutrients in the system and mitigate the magnitude of algae blooms. FPL

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

also continues to remove sediment from the cooling canals to manage thermal efficiency. With regard to salinity management, FPL installed infrastructure to maximize achievement of the 14 mgd freshening capacity and continued permitting a Supplemental Salinity Management Plan ("SMP") to increase the freshening capacity to achieve the CCS salinity threshold of 34 practical salinity units ("PSU") required by the CO. The annual average CCS salinity for June 2020-May 2021 was 39.2 PSU, which is the lowest annual CCS salinity recorded since 1988. The Supplemental SMP will help FPL reduce salinity further to achieve the 34 PSU annual average requirement.

Project Costs:
(January 1, 2021 to December 31, 2021)
FPL O&M - Project expenditures are estimated to be $8,166,607, which is $1,579,504, or 16.2% lower than previously projected. The variance is primarily due to the reduced need for well maintenance and testing and the decision to maintain, rather than increase, the current sediment removal rate to achieve required thermal efficiency for the cooling canal system.

FPL Capital - Project revenue requirements are estimated to be $7,039,623, which is $231,899 or 6.0% lower than previously projected.

Project Projections:
(January 1, 2022 to December 31, 2022)
O&M - Estimated project costs for the projection period are $9,989,250.

Capital - Estimated project revenue requirements for the projection period are $7,467,893.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Martin Plant Barley Barber Swamp Iron Mitigation Project

Project No. 44

Project Description:

Martin Plant Barley Barber Swamp Iron Mitigation Project was installed in 2011. The project included the installation of complete siphon systems to mitigate iron discharges in the Barley Barber Swamp. The systems, which use cooling pond water (low iron) to hydrate the swamp, are required by permit.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)
There is no new activity scheduled in 2021.

Project Costs:

(January 1, 2021 to December 31, 2021)
FPL Capital - Project revenue requirements are estimated to be $14,310, which is on target for 2021.

Project Projections:

(January 1, 2022 to December 31, 2022)
Capital - Estimated project revenue requirements for the projection period are $14,180.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: NPDES Permit Renewal Requirements

Project No. 47

Combined Project

- **FPL Project 47 - NPDES Permit Renewal Requirements**
- **Gulf Project 9 - Crist Dechlorination System, Project 12 - Crist IWW Sampling System, and Project 25 - Plant NPDES Permit Compliance Projects - Includes toxicity sampling costs from Project 427 - General Water Quality in 2022**

Project Description:

The Federal Clean Water Act requires all point source discharges into navigable waters from industrial facilities to obtain permits under the NPDES program. See 33 U.S.C. Section 1342. Pursuant to the EPA's delegation of authority, the DEP implements the NPDES permitting program in Florida. Affected facilities are required to apply for renewal of the 5-year-duration NPDES permits prior to their expiration.

NPDES wastewater permits require reductions in chlorine concentrations prior to discharge from the plant. The GCEC dechlorination system uses sodium bisulfite to chemically eliminate the residual chlorine present in the plant industrial wastewater prior to discharge. The system has been effective in maintaining chlorine discharge limits.

The water quality based copper effluent limitations included in Chapter 62 Part 302, Florida Administrative Code ("F.A.C.") were amended in 2002. The more stringent hardness-based standard is included by reference in the GCEC NPDES industrial wastewater permit. The plant installed stainless steel condenser tubes on Unit 6 during 2006 in an effort to meet the revised water quality standards during times of lower hardness in the river water. The second phase of the project was completed in the 2008-2010 timeframe, which involved installing a chemical treatment and aeration system in the wastewater treatment pond. Due to copper exceedances in the 2017 timeframe an additional copper study was conducted that recommended retubing the Unit 6C service water cooler and Units 4 and 5 condensers with stainless steel tubes to eliminate these copper sources. The 6C cooler project was completed in 2019 and the unit 4&5 condenser tube replacement project was completed in 2020.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

The GCEC industrial wastewater sampling system includes an access dock in the discharge canal and a small building for monitoring and sampling equipment. The sampling system is used to collect samples required by the facility's industrial wastewater permit.

In 2019, Plant Smith completed replacement of the second discharge canal crossover to allow for continued safe access for obtaining representative main plant discharge samples as required by the Plant Smith NPDES wastewater permit.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

FPL - All NPDES IWW permits are currently in the renewal process. The 2019 pilot study for the use of chlorine dioxide to replace sodium hypochlorite (bleach) as a biocide in the St. Lucie plant's cooling water system was effective and PSL received a minor permit revision from DEP on May 21, 2021 to use chlorine dioxide as an approved biocide. Also during 2021, FPL conducted Whole Effluent Toxicity Testing at its Cape Canaveral, Ft. Myers, Riviera, Port Everglades, and St. Lucie plants.

Gulf- The new GCEC caustic system was completed in June 2021 to increase the pH of the service water system. Increasing the pH of the service water reduces the copper corrosion rate.

Project Costs:

(January 1, 2021 to December 31, 2021)

FPL O&M

Project 47 - NPDES Permit Renewal Requirements - Project expenditures are estimated to be -$4,234, which is $85,230, or 105.2% lower than estimated. The variance is primarily due to St. Lucie Nuclear Plant projections inadvertently including costs associated with chemicals which are recovered through base rates.

Gulf O&M - The 2021 toxicity sampling costs for Gulf are included under the General Water Quality line item.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

FPL Capital

Project 47 - NPDES Permit Renewal Requirements - Project revenue requirements are estimated to be $370,228, which is $68,806, or 22.8% higher than previously projected. The variance is primarily due to materials & equipment and engineering costs related to the PSL chlorine dioxide project which were not known at the time of the 2021 Projection Filing.

Gulf Capital

Project 9 - Crist Dechlorination System - Project revenue requirements are estimated to be $21,977, which is on target for 2021.

Project 12 - Crist IWW Sampling System – Project revenue requirements are estimated to be $2,651 which is on target for 2021.

Project 25 - Plant NPDES Permit Compliance Projects – Project revenue requirements are estimated to be $1,263,624, which is $60,300 or 5.0% higher than previously projected

Project Projections:

(January 1, 2022 to December 31, 2022)

O&M - Estimated project costs for the projection period are $176,574.

Capital - Estimated project revenue requirements for the projection period are $2,100,495.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Industrial Boiler MACT Project

Project No. 48

Project Description:

40 CFR Part 63 Subpart JJJJJ Final Rule for National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers was published on March 21, 2011. 40 CFR Part 63 Subpart DDDDD Final Rule for National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters was published on November 20, 2015. FPL must complete energy audits, inspections and boiler tune-ups as well as comply with recordkeeping requirements for boilers and heaters that are subject to these rules.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

FPL's Industrial Boiler MACT project includes required boiler tuning for the affected units and one-time performance of a site energy audit for each site. FPL has performed required boiler tunings at FPL's Martin Fuel Oil Terminal and the auxiliary boilers at its Fort Myers, Lauderdale, Martin, and West County power generation facilities. The auxiliary boilers at Fort Myers, Lauderdale and at FPL's Martin Fuel Oil Terminal have been retired.

Project Costs:

(January 1, 2021 to December 31, 2021)

FPL O&M - Project costs are estimated to be $31,668, which is $33,332 or 51.3% lower than previously projected.

Project Projections:

(January 1, 2022 to December 31, 2022)

O&M - Estimated project costs for the projection period are $13,000.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Steam Electric Effluent Limitation Guidelines Revised Rule

Project No. 50

Combined Project

- **FPL Project 50 - Steam Electric Effluent Limitation Guidelines Revised Rule**
- **Gulf Project 29 - Steam Electric Effluent Limitations Guidelines**

Project Description:

In 2015, EPA finalized revisions to the steam electric effluent limitations guidelines ("ELG") rule, which imposes stringent technology-based requirements for certain waste streams from steam electric generating units. The revised technology-based limits and compliance dates will require extensive modifications to existing ash and flue gas desulfurization ("FGD") scrubber wastewater management systems or the installation and operation of new wastewater management systems. Compliance dates in the 2015 rule ranged from November 1, 2018 to December 31, 2023.

On September 18, 2017, EPA published a final rule in the Federal Register that delayed the earliest compliance date from the original 2015 rule from November 1, 2018 to November 1, 2020, to allow time for EPA to reconsider the requirements for FGD wastewater and bottom ash transport water. The 2017 rule did not change the latest compliance date of December 31, 2023.

On August 31, 2020, EPA published the final ELG Reconsideration Rule. The rule revises requirements for two specific waste streams: FGD wastewater and bottom ash ("BA") transport water. The compliance date for the Rule is now no later than December 31, 2025 or December 31, 2028 if the Voluntary Incentives Program is selected. State environmental agencies will incorporate specific applicability dates in the NPDES permitting process based on requirements provided for each waste stream.

On August 3, 2021, EPA announced plans to initiate rulemaking to revise the ELG requirements for FGD scrubber wastewater and bottom ash transport water. EPA plans to propose a revised rule in the of Fall 2022. The 2020 Rule remains in effect during the rulemaking process. Effects of the new rule are dependent on the revisions made through the rulemaking effort.

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PROJECT DESCRIPTION AND PROGRESS

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

FPL - Georgia Power, the operating agent for Plant Scherer, continued to conduct studies evaluating technologies to determine the costs for various methods of complying with the ELG Rule. Activities necessary to achieve compliance will continue because the revised Rule has not been issued.

Gulf - Capital costs projected in 2021 for engineering and design of the Scherer scrubber wastewater treatment system have been delayed to 2022. A feasibility study is ongoing to evaluate technologies being considered.

Project Costs:

(January 1, 2021 to December 31, 2021)

FPL O&M - Project expenditures are $43,726 versus an original estimate of $0.

FPL Capital - Project revenue requirements are estimated to be $109,680, which is $275,511, or 71.5% lower than previously projected. The variance is primarily due to the 2020 Steam Electric Reconsideration Rule, which went into effect subsequent to FPL's last projection filing. The new rule extended compliance dates, which postponed capital expenditures.

Gulf Capital - Project revenue requirements are estimated to be $666,190, which is $68,135 or 9.3% lower than previously projected.

Project Projections:

(January 1, 2022 to December 31, 2022)

O&M - Estimated project costs for the projection period are $2,086,610.

Capital - Estimated project revenue requirements for the projection period are $754,942.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Gopher Tortoise Relocation Project

Project No. 51

Project Description:

The gopher tortoise (*Gopherus polyphemus*) is a state-designated threatened species, per Rule 68A-27.003(1)(d)3, F.A.C. Gopher tortoises have been creating burrows in the cooling pond embankments at FPL's Martin, Manatee and Sanford plants over time, as well as in the oil tank farm embankments at Martin and Manatee plants. Gopher tortoise burrows must be inspected and then filled as necessary to ensure the integrity of the embankments. Filling burrows means that affected gopher tortoises must be relocated. In 2008, the FWC provided new gopher tortoise guidelines that have changed the permitting process for relocations. An authorized gopher tortoise agent is now required to conduct surveys and perform relocations, and all tortoises now must be sent to a recipient site.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

Gopher tortoise relocations have taken place at the Martin plant and are currently in progress at the Manatee Plant. FPL will continue to monitor gopher tortoise activity throughout the year at Sanford, Martin, and Manatee plants' cooling ponds and the Manatee fuel oil storage terminal.

Project Costs:

(January 1, 2021 to December 31, 2021)

FPL O&M - Project costs are estimated to be $39,523 which is on target for 2021.

Project Projections:

(January 1, 2022 to December 31, 2022)

O&M - Estimated project costs for the projected period are $36,318.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Coal Combustion Residuals

Project No: 54

Combined Projects

- **FPL Project 54 - Coal Combustion Residuals**
- **Gulf Project 23 and 28 - Coal Combustion Residuals**

Project Description:

The final rule entitled, "Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities," which became effective October 19, 2015 and is found in 40 CFR Parts 257 and 261, regulates the disposal of coal combustion residuals ("CCR") generated from the combustion of coal in new and existing impoundments and landfills at electric utilities and independent power producers. Subsequent amendments, court decisions and the WIIN Act have modified the 2015 requirements by extending deadlines for closure, additional beneficial use, and approval of state CCR permitting programs. The rule applies to CCR Units at the St. Johns River Power Park, ("SJRPP"), GCEC, Scherer, Smith, and Daniel. In addition, a NPDES permit renewal for Plant Scholz (FL0002283) was issued in 2015 which requires closure of the existing on-site ash pond. Costs required to complete the Scholz pond closure are included under this project. The Georgia Environmental Protection Division's ("Georgia EPD") adoption of the CCR rule at 391-3-4-.10 was approved by USEPA effective February 20, 2021. The Georgia EPD rule establishes a permit program for CCR impoundments and landfills in addition to the Federal CCR criteria.

The CCR rule established requirements for location, design, operation, safety, public disclosure and closure of CCR impoundments and landfills at electric utilities. Existing facilities that fail to meet certain criteria including the location requirements, are required to cease receiving CCR and initiate closure of the disposal unit. The location criteria include a requirement for unlined surface impoundments to be located at least 5 feet above the uppermost aquifer with no hydraulic connection between the base of the unit and the aquifer.

The rule set specific schedules for implementation of each of the performance requirements including installation of a groundwater monitoring system implementation of a detection monitoring plan, routine inspections, demonstration of compliance with location restrictions or no groundwater contact,

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PROJECT DESCRIPTION AND PROGRESS

development of the CCR unit closure plan, and Professional Engineer inspections. Unlined impoundments such as the Daniel, Scherer, and Smith ash ponds were required to cease receipt of CCR and non-CCR wastewater by April 11, 2021 and initiate closure within 30 days.

FDEP recently initiated rulemaking to revise the state permitting requirements to include CCR facilities and incorporate existing federal CCR rule provisions into the state solid waste regulations. Under the new state CCR rule, CCR units in Florida will be required to obtain a CCR permit from FDEP prior to beginning any new CCR closure projects. Facilities will also be required to submit a state CCR permit application and supporting documentation for all existing CCR units in 2022.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

FPL - While SJRPP was retired on January 5, 2018, the CCR rule compliance requirements for ash which was previously produced at the plant continues. SJRPP submitted a notice of intent to initiate closure of byproduct storage Area B in December of 2020 and plans to close the area in place by installing a final cover system to reduce infiltration. Additional wells have been installed to meet the groundwater monitoring requirements. Georgia Power ("GPC"), as the Plant Scherer operating partner, has completed evaluation of the ash impoundment and determined that it is an unlined unit that does not meet the CCR rule location restriction requirements. Groundwater monitoring wells have been installed and initial background monitoring has begun. GPC submitted its notification of intent to initiate closure of the ash pond in October of 2020 and plans to excavate ash from the northern area of the pond and consolidate it in the southern portion of the pond that will be closed in place. Construction of the CCR wastewater management systems continued in 2021 and early site work is being initiated for the ash pond closure project.

Gulf - During 2021, construction activities continued for the Daniel, Scholz, and Smith pond closure projects. CCR wastewater treatment and water management required for the pond closure projects also continued. The 2021 Plant Daniel closure activities include dewatering and ash excavation as well as backfilling the excavated pond area. Plant Daniel completed detailed design of the permanent wastewater treatment system and began construction of the system. The 2021 Scholz ash pond closure activities include transferring CCR material to a dry stack area within the footprint of the pond and construction of

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a new stormwater management system. The Plant Smith activities include ash excavation and construction of a new lined industrial wastewater treatment ponds and associated infrastructure.

Groundwater monitoring systems have been installed for all Gulf CCR units and groundwater monitoring is ongoing. The GCEC groundwater extraction system is continuing to serve as a temporary corrective measure for the gypsum storage area CCR unit while Gulf evaluates potential corrective measures available for the unit. As part of the conversion from coal to natural gas, the Company is considering closure options for the gypsum storage area (“GSA”). One potential closure option under consideration is closure by removal of CCR materials, potentially followed by conversion of the GSA to a stormwater holding pond. Gulf will be initiating closure design studies during the second half of 2021.

Construction of the Scherer CCR wastewater management system continued in 2021, which included installing wastewater treatment systems for wastewater streams that were previously routed to the ash pond. Plant Scherer initiated early site work outside of the ash pond boundary that will be required to support pond closure. Early site work includes construction of laydown areas, access road improvements, and preparing wastewater treatment plant area. Construction of Cell 3 of the onsite landfill at Scherer has been delayed to 2022 based on updated storage capacity need projections.

Project Costs:

(January 1, 2021 to December 31, 2021)

Gulf O&M - Project expenditures are estimated to be $1,398,716, which is $346,411 or 19.9% lower than previously projected. The variance is primarily due to removing wastewater treatment costs for the Plant Scholz pond closure project from the 2021 O&M budget since completion of the capital project has been delayed until 2022. The wastewater treatment costs will continue to be included under the pond closure capital line item until the capital project is complete.

FPL Capital - Project revenue requirements are estimated to be $11,556,346, which is $259,184 or 2.29% higher than previously projected.

Gulf Capital - Project revenue requirements are estimated to be $13,605,095, which is $1,715,693 or 11.2% lower than previously projected. The variance is primarily due to delays placing the Plant Daniel

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dry bottom ash conversion projects and the new Plant Smith industrial wastewater treatment pond in-service. Gulf initially projected the Plant Daniel dry bottom ash projects would be placed in-service in 2020; however, the projects were placed in-service in 2021. The Plant Smith wastewater pond and piping modifications required to cease discharging process water and stormwater to the ash pond were projected to be placed in-service in late 2020. Plant Smith began utilizing the new wastewater pond and piping modifications in a temporary configuration in the Spring of 2021 to meet the Federal CCR deadline to cease sending wastewater to the pond and to initiate closure; however, the associated workorder will not be placed in-service until 2023 when Plant Smith completes construction of two additional ponds and related modifications to the wastewater system.

Project Projections:

(January 1, 2022 to December 31, 2022)

O&M - Estimated project costs for the projection period are $2,407,285.

Capital - Estimated project revenue requirements for the projection period are $45,299,087.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Power Plant Intake Protected Species Project

Project No. 123

Project Description:

Under the United States Endangered Species Act ("ESA") (16 U.S.C. § 1531 et seq.), FPL is required to avoid the "take" of species listed as endangered or threatened. FPL is also required to avoid the "take" of a species listed as threatened under Chapter 68A-27 of the Florida Administrative Code. In the event FPL "takes" a species without authorization provided by the appropriate federal regulatory authority, it constitutes an unauthorized take. In the event of an unauthorized take, the appropriate federal and state wildlife agencies may require FPL to develop solutions that avoid interaction between listed species and intake structures, or apply for an incidental take permit that would require FPL to minimize or mitigate interaction between listed species and intake structures. When solutions are developed, FPL is required to implement the solution(s) at the designated facilities.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

FPL has engaged a consultant for work at the Fort Myers Plant related to the smalltooth sawfish and for work at the Cape Canaveral Energy Center related to the Florida manatee. The consultant reviewed site plans and operational details to provide options to be further investigated at the Fort Myers Plant. The consultant is also reviewing potential options for the Cape Canaveral Energy Center. FPL is working with the National Marine Fisheries Service to select the appropriate option.

Project Costs:

(January 1, 2021 to December 31, 2021)

FPL O&M - Project expenditures are $100,000, which is $100,000, or 100% lower than estimated. All costs associated with the manatee calf rehabilitation activities were removed from ECRC recovery.

FPL Capital – Project revenue requirements are estimated to be $18,217, which is $10,854 or 147.4% higher than previously projected.

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Project Projections:

(January 1, 2022 to December 31, 2022)

O&M – Estimated costs are projected to be $0 for the projection period.

Capital – Project revenue requirements are projected to be $185,636.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: FPL Miami-Dade Clean Water Recovery Center ("CWRC") Project

Project No. 124

Project Description:

Pursuant to an agreement with Miami-Dade County ("MDC"), and to further compliance with environmental and reclaimed water reuse requirements, FPL plans to construct and operate a wastewater reuse system comprised of a waterline from MDC Water and Sewer Department's South District Wastewater Treatment Plant to the Turkey Point Clean Energy Center ("Turkey Point"), an advanced reclaimed water treatment facility, and an underground injection control ("UIC") system. The wastewater reuse system will transport and further treat reclaimed water for use at Turkey Point's natural gas plant, Unit 5.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

In 2021, FPL is working on engineering and permitting efforts. Specifically, FPL is currently seeking the following approvals: Site Certification Modification, UIC Permit, Clean Water Act ("CWA") Nationwide 58 permit verification, Section 408 authorization, and Miami-Dade County administrative site plan review. FPL is also performing the preliminary engineering design for the CWRC project.

Project Costs:

(January 1, 2021 to December 31, 2021)

FPL O&M - Project expenditures are estimated to be $0.

FPL Capital - Project revenue requirements are estimated to be $39,327.

Project Projections:

(January 1, 2022 to December 31, 2022)

O&M – Project expenditures are projected to be $0.

Capital – Project revenue requirements are projected to be $1,025,717.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Air Quality Assurance Testing

Project No. 401

Project Description:

The Air Quality Assurance Testing project includes the audit test trailer and associated support equipment used to conduct Relative Accuracy Test Audits (“RATAs”) on the Continuous Emission Monitoring Systems (“CEMS”) as required by the 1990 Clean Air Act Amendments (“CAAA”). The equipment provides the accuracy and reliability needed to measure SO2, NOx, and CO2 and to further maintain compliance with CAAA requirements.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

There is no new activity scheduled in 2021.

Project Costs:

(January 1, 2021 to December 31, 2021)

Gulf Capital - Project revenue requirements are estimated to be $16,218, which is on target for 2021.

Project Projections:

(January 1, 2022 to December 31, 2022)

Capital - Estimated project revenue requirements for the projection period are $16,076.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: GCEC 5, 6 & 7 Precipitator Projects

Project No. 402

Project Description:

The GCEC precipitator projects were necessary to improve particulate removal capabilities. The larger more efficient precipitators with increased collection areas improved particulate collection efficiency and reduced particulate emissions. The upgraded Unit 7 precipitator was placed in service in 2004 as part of the Florida Department of Environmental Protections ("FDEP") NOx Reduction Agreement. The Unit 6 precipitator upgrade was placed in service in 2012.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

There is no new activity scheduled in 2021.

Project Costs:

(January 1, 2021 to December 31, 2021)

Gulf Capital - Project revenue requirements are estimated to be $2,621,305, which is on target for 2021.

Project Projections:

(January 1, 2022 to December 31, 2022)

Capital - Estimated project revenue requirements for the projection period are $3,044,987.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: GCEC Unit 7 Flue Gas Conditioning

Project No. 403

Project Description: This project included equipment required for the injection of sulfur trioxide into the flue gas to enhance particulate removal and improve the collection characteristics of fly ash. Retirement of the GCEC Unit 7 flue gas conditioning system was completed in 2005.

Project Accomplishments:
(January 1, 2021 to December 31, 2021)
There is no new activity scheduled in 2021.

Project Costs:
(January 1, 2021 to December 31, 2021)
Gulf Capital - Project revenue requirements are estimated to be $102,230, which is on target for 2021.

Project Projections:
(January 1, 2022 to December 31, 2022)
Capital - Estimated project revenue requirements for the projection period are $122,480.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: GCEC Cooling Tower Cell

Project No. 408

Project Description: The GCEC cooling tower is a pollution control device which allows condenser cooling water to be continually reinjected into the condenser. The cooling tower reduces water discharge temperatures in order to meet the National Pollution Discharge Elimination System ("NPDES") Industrial Wastewater ("IWW") permit requirements. The GCEC has maintained compliance with the temperature discharge limits as required by the facility's NPDES IWW permit. The original Unit 7 cooling tower cell was retired in 2007 when the new cooling tower was placed-in-service as part of the GCEC scrubber project that is reflected in Air Quality Compliance Program.

Project Accomplishments:
(January 1, 2021 to December 31, 2021)
There is no new activity scheduled in 2021.

Project Costs:
(January 1, 2021 to December 31, 2021)
Gulf Capital - Project revenue requirements are estimated to be $36,269, which is on target for 2021.

Project Projections:
(January 1, 2022 to December 31, 2022)
Capital - Estimated project revenue requirements for the projection period are $43,453.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: GCEC Diesel Fuel Oil Remediation

Project No. 410

Project Description: The GCEC diesel fuel oil remediation project included installation of monitoring wells in the vicinity of the GCEC diesel tank system. The project also included the installation of an impervious cap to reduce migration of contaminants to groundwater as required by FDEP.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

There is no new activity scheduled in 2021.

Project Costs:

(January 1, 2021 to December 31, 2021)

Gulf Capital - Project revenue requirements are estimated to be $1,073, which is on target for 2021.

Project Projections:

(January 1, 2022 to December 31, 2022)

Capital - Estimated project revenue requirements for the projection period are $1,050.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Sodium Injection System

Project No. 413

Project Description: The sodium injection project included silo storage systems and associated components which injected sodium carbonate directly onto the coal feeder belt to enhance precipitator performance when burning low sulfur coal. Sodium injection was used at Plant Smith for Unit 1 and 2, and was used at the GCEC for Unit 4 and 5. The injection of sodium carbonate as an additive to low sulfur coal reduced opacity levels in order to maintain compliance with the Clean Air Act provisions. The Smith Sodium Injection system was retired in 2016 after the coal units ceased operations. The GCEC sodium injection system was retired when the plant ceased coal-fired operations.

Project Accomplishments:
(January 1, 2021 to December 31, 2021)
Capital – The GCEC sodium injection system was retired when Gulf ceased coal fired operations.

Project Costs:
(January 1, 2021 to December 31, 2021)
Gulf Capital - Project revenue requirements are estimated to be $9,187, which is on target for 2021.

Project Projections:
(January 1, 2022 to December 31, 2022)
Capital - Estimated project revenue requirements for the projection period are $11,007.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Smith Stormwater Collection System

Project No. 414

Project Description: The NPDES stormwater program requires industrial facilities to install stormwater management systems in order to prevent the discharge of impacted stormwater to the surface waters of the United States. The Plant Smith stormwater sump system has been effective in managing onsite stormwater.

Project Accomplishments:
(January 1, 2021 to December 31, 2021)
There is no new activity scheduled in 2021.

Project Costs:
(January 1, 2021 to December 31, 2021)
Gulf Capital - Project revenue requirements are estimated to be $156,019, which is on target for 2021.

Project Projections:
(January 1, 2022 to December 31, 2022)
Capital - Estimated project revenue requirements for the projection period are $150,575.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Smith Waste Water Treatment Facility

Project No. 415

Project Description: During the 1990s a domestic wastewater treatment facility was installed at Plant Smith to replace the septic tank system that was originally installed in the early 1960s. In 2004 a new wastewater treatment facility was installed to replace the facility installed in the 1990's. The new treatment plant included aeration and chlorination of the wastewater prior to discharge in the Plant Smith ash pond. Following retirement of the coal-fired units and associated staffing reductions, a new wastewater treatment facility with lower capacity was installed. Plant Smith has maintained compliance with the domestic wastewater treatment requirements in the NPDES IWW permit.

Project Accomplishments:
(January 1, 2021 to December 31, 2021)
There is no new activity scheduled in 2021.

Project Costs:
(January 1, 2021 to December 31, 2021)
Gulf Capital - Project revenue requirements are estimated to be $81,876, which is on target for 2021.

Project Projections:
(January 1, 2022 to December 31, 2022)
Capital - Estimated project revenue requirements for the projection period are $89,631.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Daniel Ash Management Project

Project No. 416

Project Description: The original Daniel ash management project included the installation of a dry fly ash transport system, lining for the bottom of the ash pond, closure and capping of the existing fly ash pond, as well as expansion of the landfill area. In 2006, Plant Daniel completed construction of a new on-site ash storage facility in preparation for the completion and closure of the existing landfill area. Portions of the original Daniel ash storage facility were closed in place during 2010.

Project Accomplishments:
(January 1, 2021 to December 31, 2021)
There is no new activity scheduled in 2021.

Project Costs:
(January 1, 2021 to December 31, 2021)
Gulf Capital - Project revenue requirements are estimated to be $1,201,630, which is on target for 2021.

Project Projections:
(January 1, 2022 to December 31, 2022)
Capital - Estimated project revenue requirements for the projection period are $1,018,936.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: GCEC FDEP Agreement for Ozone Attainment (Capital)

FDEP NOx Reduction Agreement (O&M)

Project No. 419

Project Description: The Florida Department of Environmental Protection ("FDEP") and Gulf entered into an agreement on August 28, 2002 to support Escambia/Santa Rosa County area's effort to maintain compliance with the 8-hour ozone ambient air quality standards. This agreement included a requirement for the GCEC to install Selective Catalytic Reduction ("SCR") controls on Unit 7, relocate the Unit 7 precipitator, and install a NO_x reduction technology on Unit 6, and if necessary, Units 4 and 5. The O&M costs associated with this project included anhydrous ammonia, air monitoring, catalyst regeneration, and general operation and maintenance expenses.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

Capital - Replacement of the existing GCEC plant alert system will be completed in 2021. The existing system has approached the end of its useful life due to obsolete and failing components.

O&M - There is no new activity scheduled in 2021.

Project Costs:

(January 1, 2021 to December 31, 2021)

Gulf O&M - Project expenditures are estimated to be -$16,223, which is $113,901 or 116.6% lower than previously projected. Maintenance costs associated with the GCEC Unit 7 Selective Catalytic Reduction ("SCR") were reduced due to retiring the SCR with the GCEC coal generation assets in October 2020.

Gulf Capital - Estimated project revenue requirements for the projection period are $6,906,690, which is on target for 2021.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Projections:

(January 1, 2022 to December 31, 2022)

O&M - Estimated project costs for the projection period are $0.

Capital - Estimated project revenue requirements for the projection period are $7,862,030.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Precipitator Upgrades for Compliance Assurance Monitoring

Project No. 422

Project Description: Compliance assurance monitoring ("CAM") precipitator upgrades were required to comply with new CAM regulations incorporated into Gulf's Title V permits in the 2005 time frame. CAM requirements are regulated under Title V of the 1990 CAAA, which requires a method of continuously monitoring particulate emissions. Opacity can be used as a surrogate parameter if the precipitator demonstrates a correlation between opacity and particulate matter. Gulf demonstrated this correlation by stack testing in 2003 and 2004, and the results were included as part of the CAM plans in Gulf's Title V air permits effective January 2005. Several precipitator upgrades have been necessary to meet the more stringent surrogate opacity standards under CAM.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

There is no new activity scheduled in 2021.

Project Costs:

(January 1, 2021 to December 31, 2021)

Capital - Project revenue requirements are estimated to be $520,432, which is on target for 2021.

Project Projections:

(January 1, 2022 to December 31, 2022)

Capital - Estimated project revenue requirements for the projection period are $623,520.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Air Quality Compliance Program

Project No. 426

Combined Projects

- **FPL Project 29 - Selective Catalytic Reduction Systems ("SCR") Consumables, Project 31 - Clean Air Interstate Rule ("CAIR") Compliance, Program 33 - Mercury Air Toxics Standard ("MATS"), and Program 45 - 800 MW Unit ESP**
- **Gulf Project 20 - and 26 - Air Quality Compliance Program**

Project Description:

In response to the Clean Air Act requirements that EPA establish National Ambient Air Quality Standards ("NAAQS") that are protective of human health and the environment with an adequate margin of safety, EPA, and states promulgate rules to ensure that the ambient air to which the public is exposed meets and maintains standards that are protective of human health and the environment with an adequate margin of safety. EPA also establishes pollutant performance standards for new emission units to prevent significant deterioration of the NAAQS. New emission units must demonstrate that the design incorporates Best Available Control Technology ("BACT") to ensure implementation of cost-effective emission controls. EPA and the state environmental agencies, including the Florida Department of Environmental Protection ("FDEP") make the determination whether the proposed controls represent BACT.

During FPL's engineering and construction of the combined cycle units of Turkey Point Unit 5, Martin Unit 8, and Manatee Unit 3, the FDEP revised its BACT standards for emission of Nitrogen Oxides ("NOx") from combined cycle units requiring implementation of Selective Catalytic Reduction ("SCR"). To comply with the new control requirements FPL implemented the SCR Consumables project to provide for costs associated with operating the additional controls that were not included in the proposed costs that were to be recovered under base rates.

In response to ozone and fine particulate ambient air quality standard revisions EPA promulgated the Clean Air Interstate Rule ("CAIR") to address non-attainment areas within states and transport of pollutants from upwind fossil generating units to downwind non-attainment areas. CAIR, and subsequently the Cross-State Air Pollution Rule ("CSAPR") that replaced CAIR, established emission budgets for affected generating units under a new cap-and-trade emission allowance program. FPL's

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

CAIR project, and Gulf's Air Quality Compliance Program, implemented strategies to comply with Annual and Ozone Season NOx and SO_2 emissions requirements for its affected fossil generating units. The CAIR project has included engineering studies for minimizing compliance costs, modification of FPL's 800 MW units (Martin Plant Units 1 and 2, Manatee Plant Units 1 and 2) to reliably cycle units, the construction and operation of SCRs on St. Johns River Power Park ("SJRPP") Units 1 and 2, the construction and operation of the scrubber and SCR for Scherer Unit 4, and the installation of CEMS for the peaking gas turbine units. Similarly, to comply with CAIR emission budgets Gulf prudently incurred costs for the GCEC scrubber, SNCRs, and SCRs, the Daniel scrubber and injection systems, as well as air controls for the Company's ownership share of the Scherer 3 SCR, and scrubber projects and associated equipment. CAIR project O&M primarily includes the cost of anhydrous ammonia, hydrated lime, limestone and general expenses. SJRPP was retired January 5, 2018 and Martin Plant Units 1 and 2 were retired in December of 2018.

To address emissions of Hazardous Air Pollutants ("HAPs") from coal and oil-fired electric generating units EPA promulgated the Clean Air Mercury Rule ("CAMR") in 2005 which was subsequently replaced by the Mercury and Air Toxics Standard ("MATS") in 2013. Following the promulgation of the CAMR program the Georgia Environmental Protection Division ("GAEPD") issued its rules for control of coal-fired power plant emissions through its Multi-Pollutant rule which required installation of controls and imposed additional monitoring requirements. To comply with the EPA and GAEPD rules the owners of Plant Scherer installed baghouses and activated carbon injection systems on all 4 coal-fired units with Gulf and FPL responsible for their ownership share of Scherer Units 3 & 4. FPL and JEA also installed Mercury CEMS on SJRPP Units 1 & 2 to comply with the monitoring requirements of MATS. To retain oil combustion capability in compliance with the MATS emission standards for its oil-fired 800 MW fossil steam generating units, FPL installed Electrostatic Precipitators ("ESP") on Martin Units 1 & 2 and Manatee Units 1 &2.

FPL retired Martin Units 1 & 2 in 2018, SJRPP Units 1 & 2 in 2018 and plans to retire Scherer Unit 4 by 2022. Additionally, as a result of damages to plant equipment because of Hurricane Michael, the GCEC ceased coal operation in 2020 and operates on natural gas with limited oil use during startup.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

FPL O&M

Project 29 - SCR Consumables - Manatee annual training has been completed and inspections and calibrations of equipment will be completed this fall during the outage.

Required calibration of Martin Plant Unit 8 SCR system instrument and controls was performed. The Martin Plant Unit 8 HRSG Anhydrous Ammonia Blower Injection Skid Auto Shutoff Valve was replaced and the internal disc of the snappy joe valve was replaced. Additionally, anhydrous ammonia is purchased as needed throughout the year.

Project 31 - Clean Air Interstate Rule 2021 O&M activities associated with the 800MW cycling project were primarily related to water demineralization and the use of chemicals for treatment of biological fouling of condenser tubes at Manatee Plant Units 1 and 2. Project O&M at Scherer includes routine maintenance of the SCR and scrubber and associated limestone sorbent costs for removal of SO_2 and ammonia costs for control of NOx.

Project 33 - MATS – For Plant Scherer, operation for the baghouse and sorbent injection system continues per the requirements of the State of Georgia Multi Pollutant Rule and MATS.

Project 45 - 800 MW ESPs - The Manatee Plant systems will continue to operate until the units are retired, with costs for payroll, materials, and contractors. These costs are associated with inspections, ash disposal, blower motor replacement, preventative maintenance, and repairs needed to operate and maintain the system.

Gulf O&M

Project 20 - Air Quality Compliance Program - Existing air quality controls have ensured compliance with state and federal regulations. Chemical and maintenance costs required for Gulf's ownership portion of the Daniel and Scherer air controls are included under this line item which includes general maintenance, limestone, anhydrous ammonia, and sorbent injection costs. Gulf has projected costs to terminate the GCEC limestone contract in 2021 due to ceasing coal-fired operations. Gulf is continuing to incur costs

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

to treat wastewater and stormwater runoff from the gypsum storage area while gypsum is being reclaimed from the storage area for reuse.

Gulf Capital

Project 26 - Air Quality Compliance - During 2021, the GCEC will be installing a new continuous emission monitoring (“CEMS”) system and completing construction of the Underground Injection Control (“UIC”) pipeline expansion. The UIC expansion will allow the plant to utilize two additional wells for disposal of wastewater generated from the gypsum storage area. The GCEC also plans to close the anhydrous ammonia tanks that were installed for the Unit 7 SCR project. The Unit 7 SCR was retired when the plant ceased coal-fired operations. Plant Daniel completed the Unit 1 Low NOx burner replacement in early 2021 and will be replacing Unit 2 scrubber mist eliminator and several scrubber valves later in 2021. The Scherer Unit 3 digital control system is being upgraded in 2021.

Project Costs:

(January 1, 2021 to December 31, 2021)

FPL O&M

Project 29 - SCR Consumables – Project expenditures are estimated to be $464,147, which is on target for 2021.

Project 31 - Clean Air Interstate Rule (“CAIR”) Compliance - Project expenditures are estimated to be $3,949,873, which is $58,823 or 1.5% higher than previously projected.

Project 33 - MATS - Project expenditures are estimated to be $1,618,628, which is $802,154, or 33.1% lower than previously projected. The variance is primarily due to lower than projected operation of Scherer Unit 4, which resulted in lower operating costs for the sorbant injection system.

Project 45 - 800 MW ESP’s - Project expenditures are estimated to be $75,000, which is $189,099, or 71.6% lower than previously projected. The decrease is primarily due to the anticipated dismantlement of Manatee Units 1&2 and the determination that scheduled ESP work was no longer required.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Gulf O&M

Project 20 - Air Quality Compliance Program – Project costs are estimated to be $22,428,670, which is $1,244,346 or 5.3% lower than previously projected.

FPL Capital

Project 31 - Clean Air Interstate Rule ("CAIR") Compliance – Project revenue requirements are estimated to be $44,416,116, which is on target for 2021.

Project 33 - MATS – Project revenue requirements are estimated to be $9,233,085, which is on target for 2021.

Project 45 - 800 MW ESP's - Project revenue requirements are estimated to be $18,459,289, which is on target for 2021.

Gulf Capital

Project 26 - Air Quality Compliance Program – Project revenue requirements are estimated to be $101,587,778, which is $1,423,782 or 1.4% higher than previously projected.

Project Projections:

(January 1, 2022 to December 31, 2022)

O&M - Estimated project costs for the projection period are $8,058,361.

Capital - Estimated project revenue requirements for the projection period are $190,998,924.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: General Water Quality

Project No. 427

Project Description: The General Water Quality program includes activities undertaken pursuant to the GCEC, Smith, and Scholz NPDES industrial wastewater ("IWW") and stormwater permits. The O&M costs include dechlorination, stormwater maintenance, impoundment integrity, as well as surface and groundwater monitoring and associated studies. For 2021 the General Water Quality line item includes expenses for Gulf's 316(b) Cooling Water Intake program and toxicity sampling. For 2022 Gulf's 316(b) O&M costs are included under Project 28. CWA 316(b) Phase II Rule and toxicity sampling costs are included under Project 47. NPDES Permit Renewal Requirements for consistency with comparable FPL costs.

Capital costs include groundwater monitoring wells and the GCEC closed ash landfill ("CAL") project. The GCEC industrial wastewater permit and FDEP Order 17-1224 require the plant to complete FDEP approved rehabilitation actions by July 23, 2023 for the CAL. The surface of the CAL will be regraded and then it will be capped with a low permeability synthetic material to reduce water infiltration, to provide separation of ash and stormwater, and to provide stability improvements as recommended in the FDEP action plan that was approved on August 28, 2019.

Project Accomplishments:
(January 1, 2021 to December 31, 2021)
Gulf O&M - Activities are on-going in compliance with applicable environmental laws, rules, and regulations.

Gulf Capital - GCEC CAL pre-construction activities including contractor mobilization, material procurement, erosion and sediment control installation, and vegetation clearing were conducted during the first half of 2021.

Project Costs:
(January 1, 2021 to December 31, 2021)
Gulf O&M - Project expenditures are estimated to be $1,298,696, which is $334,061 or 20.5% lower than previously projected. The variance is primarily due to costs for the Plant Smith and Plant Scholz industrial

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

wastewater permit renewals being less than originally projected and costs for Plant Daniel's groundwater monitoring being lower. In addition, less substation stormwater maintenance has been required this year than originally anticipated.

Gulf Capital - Project revenue requirements are estimated to be $1,038,849, which is $289,748 or 21.8% lower than previously projected. The variance is due to costs for the GCEC Closed Ash Landfill improvement project being lower than expected in 2020, which lowered the 2021 beginning of period balance for the project. As explained in Gulf's final true-up testimony, the 2020 project costs were lower than estimated due to design and contractor procurement delays.

Project Projections:
(January 1, 2022 to December 31, 2022)
O&M - Estimated project costs for the projection period are $1,653,277.

Capital - Estimated project revenue requirements for the projection period are $2,203,075.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Emission Allowances

Project No. N/A

Combined Project

- **FPL – Deferred Gains on Emissions**
- **Gulf – Emission Allowances**

Project Description: Annual NOx and SO2 allowances are currently required for Scherer Unit 3 and Unit 4. The company has evaluated the use of banked and allocated allowances in combination of operation of emission controls on these units to comply with state rule requirements. Daniel Units 1 and 2 are affected units under the CSAPR Seasonal NOx allowance program. The NOx Ozone season allowance allocation to Plant Daniel has historically been insufficient to cover emissions from unit operation with existing controls. Purchase of CSAPR NOx Ozone Season allowances has been evaluated as the lower cost alternative compared to the installation of new control equipment and is currently required for Daniel Units 1 and 2.

Project Accomplishments:
(January 1, 2021 to December 31, 2021)
Allowances have been surrendered as required.

Project Costs:
(January 1, 2021 to December 31, 2021)
Gulf O&M - Project expenditures are estimated to be $152,622, which is $148,734 or 3,825.8% higher than previously projected. The variance is primarily due to the market price per allowance significantly increasing following changes to EPA's Cross State Air Pollution Rule.

Gulf Capital - Project revenue requirements are estimated to be $428,951, which is $8,805 or 2.0% lower than previously projected.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Projections:

(January 1, 2022 to December 31, 2022)

O&M - Estimated project costs for the projection period are -$59.

Capital - Estimated project revenue requirements for the projection period are $513,813.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Asbestos Fees

Project No. 428

Project Description: Asbestos notification fees include both annual and individual project fees due to the FDEP for asbestos abatement projects.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

Fees are paid as required by FDEP.

Project Costs:

(January 1, 2021 to December 31, 2021)

Gulf O&M - Project costs are estimated to be $1,500 which is on target for 2021.

Project Projections:

(January 1, 2022 to December 31, 2022)

O&M - Estimated project costs for the projection period are $1,500.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Environmental Auditing/Assessment

Project No. 429

Project Description: The Environmental Auditing/Assessment program ensures continued compliance with environmental laws, rules, and regulations through auditing and/or assessment of company facilities and operations.

Project Accomplishments:

(January 1, 2021 to December 31, 2021)

Assessments completed to date have demonstrated compliance with environmental laws, rules, and regulations.

Project Costs:

(January 1, 2021 to December 31, 2021)

Gulf O&M - Project costs are estimated to be $38,030, which is $5,100 or 15.5% higher than previously projected.

Project Projections:

(January 1, 2022 to December 31, 2022)

O&M - Estimated project costs for the projection period are $5,202.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: General Solid and Hazardous Waste

Project No. 430

Project Description: The General Solid and Hazardous Waste program involves the proper identification, handling, storage, transportation and disposal of solid and hazardous wastes as required by federal and state regulations. The program includes expenses for generating and power delivery facilities in the Gulf region. For 2021 the General Solid and Hazardous Waste line item includes expenses for Gulf's Spill Prevention Control and Countermeasures ("SPCC") program which includes costs associated with preparing and implementing oil spill response plans. For 2022 Gulf's SPCC O&M costs are included under Project 23. SPCC program for consistency with comparable FPL costs.

Project Accomplishments:
(January 1, 2021 to December 31, 2021)
Gulf has complied with all hazardous and solid waste regulations.

Project Costs:
(January 1, 2021 to December 31, 2021)
Gulf O&M - Project costs are estimated to be $815,298, which is on target for 2021.

Project Projections:
(January 1, 2022 to December 31, 2022)
O&M - Estimated project costs for the projection period are $907,137.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Title V

Project No. 431

Project Description: Title V expenses are associated with preparation of the CAAA Title V permit applications and the subsequent implementation of Title V permits. Renewal of the Title V permits is on a five-year cycle (i.e. 2019, 2024, etc.). Title V permits are periodically revised between renewals to incorporate major changes or modifications of a source.

Project Accomplishments:
(January 1, 2021 to December 31, 2021)
The Company has maintained compliance with its Title V permits and submitted permit renewals and modifications as required.

Project Costs:
(January 1, 2021 to December 31, 2021)
Gulf O&M - Project costs are estimated to be $195,252, which is on target for 2021.

Project Projections:
(January 1, 2022 to December 31, 2022)
O&M - Estimated project costs for the projection period are $183,107.

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-6P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
RATE CLASS	Avg 12 CP Demand Load Factor at Meter (%)	GCP Demand Load Factor at Meter (%)	Projected Sales at Meter (kWh)	Projected Avg 12 CP Demand at Meter (kW)	Projected GCP Demand at Meter (kW)	Demand Loss Expansion Factor	Energy Loss Expansion Factor	Projected Sales at Generation (kWh)	Projected Avg 12 CP Demand at Generation (kW)	Projected GCP Demand at Generation (kW)	kWh Sales at Generation (%)	12 CP Demand at Generation (%)	GCP Demand at Generation (%)
RS1/RTR1	62.2200%	48.8635%	65,315,938,669	11,983,542	15,259,164	1.0644904	1.0490795	68,521,615,430	12,756,366	16,243,234	53.5616101%	56.8932%	60.3882%
GS1/GST1	59.7119%	52.3115%	8,368,517,064	1,599,867	1,826,197	1.0644904	1.0490795	8,779,240,101	1,703,043	1,943,969	6.8625095%	7.5955%	7.2272%
GSD1/GSDT1/HLFT1/GSD1-EV	70.6122%	63.6526%	28,295,907,165	4,574,458	5,074,617	1.0643897	1.0490005	29,682,420,829	4,869,006	5,401,370	23.2019961%	21.7157%	20.0809%
OS2	105.8137%	15.5227%	9,900,936	1,068	7,281	1.0355315	1.0274402	10,172,620	1,106	7,540	0.0079517%	0.0049%	0.0280%
GSLD1/GSLDT1/CS1/CST1/HLFT2/GSLD1-EV	69.9392%	60.5468%	10,335,974,594	1,687,046	1,948,749	1.0627966	1.0478368	10,830,414,999	1,792,986	2,071,124	8.4658609%	7.9967%	7.6999%
GSLD2/GSLDT2/CS2/CST2/HLFT3	81.3272%	74.9191%	3,825,387,076	536,952	582,880	1.0520194	1.0397468	3,977,433,808	564,884	613,201	3.1090592%	2.5194%	2.2797%
GSLD3/GSLDT3/CS3/CST3	84.0124%	0%	960,788,986	130,551	0	1.0208493	1.0164079	976,553,509	133,273	0	0.7633471%	0.5944%	0%
SST1T	62.7721%	0%	65,710,604	11,950	0	1.0208493	1.0164079	66,788,776	12,199	0	0.0522071%	0.0544%	0%
SST1D1/SST1D2/SST1D3	148.2831%	0.9646%	1,410,876	109	16,698	1.0355315	1.0274402	1,449,591	112	17,291	0.0011331%	0.0005%	0.0643%
CILC D/CILC G	85.4080%	78.9461%	2,647,478,080	353,859	382,823	1.0527438	1.0404215	2,754,493,069	372,522	403,014	2.1531174%	1.6614%	1.4983%
CILC T	92.9056%	0%	1,504,497,392	184,861	0	1.0208493	1.0164079	1,529,183,023	188,715	0	1.1953236%	0.8417%	0%
MET	75.0765%	61.4199%	84,974,524	12,921	15,793	1.0355315	1.0274402	87,306,241	13,380	16,355	0.0682451%	0.0597%	0.0608%
OL1/SL1/SL1M/PL1	56,888.7476%	42.3386%	569,918,549	114	153,664	1.0644904	1.0490795	597,889,893	122	163,574	0.4673554%	0.0005%	0.6081%
SL2/SL2M/GSCU1	96.3753%	77.1123%	110,096,899	13,041	16,298	1.0644904	1.0490795	115,500,405	13,882	17,350	0.0902837%	0.0619%	0.0645%
Total			122,096,501,415	21,090,338	25,284,163			127,930,462,295	22,421,597	26,898,020	100.0000000%	100.0000%	100.0000%

Notes:

(2) Avg 12 CP load factor based on load research data and 2022 projections

(3) Avg GCP Demand load factor based on projected 2022 load research data: Column 4 / 8760 / Column 6

(4) Projected kWh sales for 2022

(5) (6) Avg CP and GCP kW based on load research data and 2022 projections

(7) Based on 2022 demand losses

(8) Based on 2022 energy losses

(9) Column 4 * Column 8

(10) Column 5 * Column 7

(11) Column 6 * Column 7

(12) Column 9 / Total for Column 9

(13) Column 10 / Total for Column 10

(14) Column 11 / Total for Column 11

FLORIDA POWER & LIGHT COMPANY
Environmental Cost Recovery Clause (ECRC)
Projection
Total Jurisdictional Amount to be Recovered

Form 42-7P

January 2022 through December 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
RATE CLASS	kWh Sales at Generation (% of Total)	12 CP Demand at Generation (% of Total)	GCP Demand at Generation (% of Total)	Energy Related Cost	12 CP Demand Related Cost	GCP Demand Related Cost	Projected Sales at Meter (kWh)	Total Environmental Costs	ECRC Factor (cents/kWh)
RS1/RTR1	53.5616101%	56.8932093%	60.3882143%	$24,487,092	$165,627,493	$4,916,749	65,315,938,669	$195,031,334	0.299
GS1/GST1	6.8625095%	7.5955473%	7.2271816%	$3,137,376	$22,112,155	$588,430	8,368,517,064	$25,837,961	0.309
GSD1/GSDT1/HLFT1/GSD1-EV	23.2019961%	21.7156966%	20.0809218%	$10,607,400	$63,218,729	$1,634,969	28,295,907,165	$75,461,098	0.267
OS2	0.0079517%	0.0049332%	0.0280316%	$3,635	$14,361	$2,282	9,900,936	$20,279	0.205
GSLD1/GSLDT1/CS1/CST1/HLFT2/GSLD1-EV	8.4658609%	7.9966939%	7.6999108%	$3,870,390	$23,279,973	$626,919	10,335,974,594	$27,777,282	0.269
GSLD2/GSLDT2/CS2/CST2/HLFT3	3.1090592%	2.5193741%	2.2797243%	$1,421,388	$7,334,401	$185,613	3,825,387,076	$8,941,402	0.234
GSLD3/GSLDT3/CS3/CST3	0.7633471%	0.5943956%	0%	$348,984	$1,730,404	$0	960,788,986	$2,079,389	0.216
SST1T	0.0522071%	0.0544076%	0%	$23,868	$158,391	$0	65,710,604	$182,259	0.277
SST1D1/SST1D2/SST1D3	0.0011331%	0.0005016%	0.0642831%	$518	$1,460	$5,234	1,410,876	$7,212	0.511
CILC D/CILC G	2.1531174%	1.6614449%	1.4983037%	$984,354	$4,836,798	$121,990	2,647,478,080	$5,943,142	0.224
CILC T	1.1953236%	0.8416671%	0%	$546,473	$2,450,261	$0	1,504,497,392	$2,996,734	0.199
MET	0.0682451%	0.0596729%	0.0608021%	$31,200	$173,720	$4,950	84,974,524	$209,870	0.247
OL1/SL1/SL1M/PL1	0.4673554%	0.0005429%	0.6081255%	$213,664	$1,581	$49,513	569,918,549	$264,757	0.046
SL2/SL2M/GSCU1	0.0902837%	0.0619128%	0.0645013%	$41,276	$180,241	$5,252	110,096,899	$226,768	0.206
Total	100.0000000%	100.0000000%	100.0000000%	$45,717,617	$291,119,970	$8,141,901	122,096,501,415	$344,979,487	0.283

(2) From Form 42-6P, Col 12
(3) From Form 42-6P, Col 13
(4) From Form 42-6P, Col 14
(5) Total Energy $ from Form 42-1P, Line 5
(6) Total CP Demand $ from Form 42-1P, Line 5
(7) Total GCP Demand $ from Form 42-1P, Line 5
(8) Col 5 + Col 6 + Col 7
(9) Projected kWh sales for the period January 2022 through December 2022
(10) Col 8 / Col 9

FORM 42-8P

CONSOLIDATED (FPL&GULF)
COST RECOVERY CLAUSES
FORECASTED 2022 CONSOLIDATED @10.60% (Proposed Settlement Rate)

CAPITAL STRUCTURE AND COST RATES (a)

	Adjusted Retail	Ratio	Midpoint Cost Rates	Weighted Cost	Pre-Tax Weighted Cost
Long term debt	$17,415,345,338	31.374%	3.61%	1.1311%	1.13%
Short term debt	$654,983,828	1.180%	0.94%	0.0111%	0.01%
Preferred stock	$0	0.000%	0.00%	0.0000%	0.00%
Customer Deposits	$455,338,901	0.820%	2.03%	0.0167%	0.02%
Common Equity [(b)]	$26,665,503,451	48.039%	10.60%	5.0921%	6.82%
Deferred Income Tax	$9,267,598,436	16.696%	0.00%	0.0000%	0.00%
Investment Tax Credits					
Zero cost	$0	0.000%	0.00%	0.0000%	0.00%
Weighted cost	$1,049,225,596	1.890%	7.84%	0.1481%	0.19%
TOTAL	$55,507,995,549	100.00%		6.3991%	8.17%

CALCULATION OF THE WEIGHTED COST FOR CONVERTIBLE INVESTMENT TAX CREDITS (C-ITC)

	Adjusted Retail	Ratio	Cost Rate	Weighted Cost	Pre-Tax Cost
Long term debt	$17,415,345,338	39.51%	3.605%	1.424%	1.424%
Preferred Stock	$0	0.00%	0.000%	0.000%	0.000%
Common Equity	$26,665,503,451	60.49%	10.600%	6.412%	8.589%
TOTAL	$44,080,848,789	100.00%		7.836%	10.013%

RATIO

DEBT COMPONENTS	
Long term debt	1.1311%
Short term debt	0.0111%
Customer Deposits	0.0167%
Tax credits weighted	0.0269%
TOTAL DEBT	**1.1858%**

EQUITY COMPONENTS:	
PREFERRED STOCK	0.0000%
COMMON EQUITY	5.0921%
TAX CREDITS -WEIGHTED	0.1212%
TOTAL EQUITY	**5.2133%**
TOTAL	6.3991%
PRE-TAX EQUITY	6.9832%
PRE-TAX TOTAL	8.1690%

Note:

(a) Forecasted capital structure pursuant to proposed Settlement in Docket No. 20210015-EI

FPL - 2022 TEST YEAR - SEPARATION FACTORS

	SUMMARY
DEMAND	
E101 - Transmission	0.902581
E102 - Non-Stratified Production	0.959314
E103INT - Intermediate Strata Production	0.954287
E103PEAK - Peaking Strata Production	0.951837
E104 - Distribution	1.000000
ENERGY	
FPL201 - Total Sales	0.946390
FPL202 - Non-Stratified Sales	0.958917
FPL203INT - Intermediate Strata Sales	0.947558
FPL203PEAK - Peaking Strata Sales	0.957721
GENERAL PLANT	
I900 - LABOR	0.969001

FLORIDA POWER & LIGHT
JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
E101 - TRANSMISSION: 12CP Demand
December 2022 - Test Year

RATE CLASS	12 CP - KW	VOLTAGE LEVEL % - DEMAND			LOSS EXPANSION FACTORS			12 CP @ GENERATION - KW				% OF TOTAL	
	@ METER	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	SYSTEM	RETAIL
CILC-1D	338,111	0.0000	0.4237	0.5763	1.0208	1.0355	1.0645	0	148,343	207,424	355,767	1.4321%	1.5867%
CILC-1G	15,748	0.0000	0.0180	0.9820	1.0208	1.0355	1.0645	0	293	16,462	16,756	0.0674%	0.0747%
CILC-1T	184,861	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	188,715	0	0	188,715	0.7597%	0.8417%
GS(T)-1	1,599,867	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	1,703,043	1,703,043	6.8556%	7.5955%
GSCU-1	8,298	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	8,833	8,833	0.0356%	0.0394%
GSD(T)-1	4,574,458	0.0000	0.0035	0.9965	1.0208	1.0355	1.0645	0	16,473	4,852,533	4,869,006	19.6002%	21.7157%
GSLD(T)-1	1,687,046	0.0000	0.0585	0.9415	1.0208	1.0355	1.0645	0	102,180	1,690,807	1,792,986	7.2177%	7.9967%
GSLD(T)-2	536,952	0.0000	0.4306	0.5694	1.0208	1.0355	1.0645	0	239,452	325,432	564,884	2.2739%	2.5194%
GSLD(T)-3	130,551	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	133,273	0	0	133,273	0.5365%	0.5944%
MET	12,921	0.0000	1.0000	0.0000	1.0208	1.0355	1.0645	0	13,380	0	13,380	0.0539%	0.0597%
OL-1	0	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	0	0	0.0000%	0.0000%
OS-2	1,068	0.0000	1.0000	0.0000	1.0208	1.0355	1.0645	0	1,106	0	1,106	0.0045%	0.0049%
RS(T)-1	11,983,542	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	12,756,366	12,756,366	51.3507%	56.8932%
SL-1	0	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	0	0	0.0000%	0.0000%
SL-1M	114	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	122	122	0.0005%	0.0005%
SL-2	4,499	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	4,789	4,789	0.0193%	0.0214%
SL-2M	244	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	260	260	0.0010%	0.0012%
SST-DST	109	0.0000	1.0000	0.0000	1.0208	1.0355	1.0645	0	112	0	112	0.0005%	0.0005%
SST-TST	11,950	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	12,199	0	0	12,199	0.0491%	0.0544%
TOTAL RETAIL	21,090,338							334,187	521,339	21,566,071	22,421,597	90.2581%	
FKEC	130,152	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	132,866	0	0	132,866	0.5348%	
FPUC (INT)	12,721	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	12,986	0	0	12,986	0.0523%	
FPUC (PEAK)	9,719	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	9,922	0	0	9,922	0.0399%	
G - FPU (INT)	30,367	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	31,000	0	0	31,000	0.1248%	
G - FPU (PEAK)	20,729	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	21,161	0	0	21,161	0.0852%	
HOMESTEAD	4,082	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	4,167	0	0	4,167	0.0168%	
HOMESTEAD (INT)	8,326	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	8,500	0	0	8,500	0.0342%	
JEA (INT)	32,653	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	33,333	0	0	33,333	0.1342%	
LCEC	791,723	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	808,230	0	0	808,230	3.2535%	
MOORE HAVEN	571	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	583	0	0	583	0.0023%	
NEW SMRYNA BCH	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0.0000%	
NEW SMYRNA BCH (INT)	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0.0000%	
NEW SMRYNA BCH (PEAK)	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0.0000%	
QUINCY	3,102	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	3,167	0	0	3,167	0.0127%	
WAUCHULA	1,878	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	1,917	0	0	1,917	0.0077%	
TRANS-SERV	1,324,609	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	1,352,226	0	0	1,352,226	5.4434%	
TOTAL WHOLESALE	2,370,630							2,420,056	0	0	2,420,056	9.7419%	
TOTAL FPL	23,460,968							2,754,244	521,339	21,566,071	24,841,653	100.0000%	
JURIS SEPARATION FACTOR												**0.902581**	

FLORIDA POWER & LIGHT
JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
E102 - NON-STRATIFIED PRODUCTION: 12CP Demand
December 2022 - Test Year

RATE CLASS	12 CP - KW			VOLTAGE LEVEL % - DEMAND			LOSS EXPANSION FACTORS			12 CP @ GENERATION - KW				% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	SYSTEM	RETAIL
CILC-1D	338,111	0	338,111	0.0000	0.4237	0.5763	1.0208	1.0355	1.0645	0	148,343	207,424	355,767	1.5222%	1.5867%
CILC-1G	15,748	0	15,748	0.0000	0.0180	0.9820	1.0208	1.0355	1.0645	0	293	16,462	16,756	0.0717%	0.0747%
CILC-1T	184,861	0	184,861	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	188,715	0	0	188,715	0.8074%	0.8417%
GS(T)-1	1,599,867	0	1,599,867	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	1,703,043	1,703,043	7.2865%	7.5955%
GSCU-1	8,298	0	8,298	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	8,833	8,833	0.0378%	0.0394%
GSD(T)-1	4,574,458	0	4,574,458	0.0000	0.0035	0.9965	1.0208	1.0355	1.0645	0	16,473	4,852,533	4,869,006	20.8322%	21.7157%
GSLD(T)-1	1,687,046	0	1,687,046	0.0000	0.0585	0.9415	1.0208	1.0355	1.0645	0	102,180	1,690,807	1,792,986	7.6713%	7.9967%
GSLD(T)-2	536,952	0	536,952	0.0000	0.4306	0.5694	1.0208	1.0355	1.0645	0	239,452	325,432	564,884	2.4169%	2.5194%
GSLD(T)-3	130,551	0	130,551	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	133,273	0	0	133,273	0.5702%	0.5944%
MET	12,921	0	12,921	0.0000	1.0000	0.0000	1.0208	1.0355	1.0645	0	13,380	0	13,380	0.0572%	0.0597%
OL-1	0	0	0	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	0	0	0.0000%	0.0000%
OS-2	1,068	0	1,068	0.0000	1.0000	0.0000	1.0208	1.0355	1.0645	0	1,106	0	1,106	0.0047%	0.0049%
RS(T)-1	11,983,542	0	11,983,542	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	12,756,366	12,756,366	54.5785%	56.8932%
SL-1	0	0	0	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	0	0	0.0000%	0.0000%
SL-1M	114	0	114	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	122	122	0.0005%	0.0005%
SL-2	4,499	0	4,499	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	4,789	4,789	0.0205%	0.0214%
SL-2M	244	0	244	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	260	260	0.0011%	0.0012%
SST-DST	109	0	109	0.0000	1.0000	0.0000	1.0208	1.0355	1.0645	0	112	0	112	0.0005%	0.0005%
SST-TST	11,950	0	11,950	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	12,199	0	0	12,199	0.0522%	0.0544%
TOTAL RETAIL	21,090,338	0	21,090,338							334,187	521,339	21,566,071	22,421,597	95.9314%	100.0000%
FKEC	130,152	0	130,152	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	132,866	0	0	132,866	0.5685%	
FPUC (INT)	12,721	(12,721)	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0.0000%	
FPUC (PEAK)	9,719	(9,719)	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0.0000%	
G - FPU (INT)	30,367	(30,367)	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0.0000%	
G - FPU (PEAK)	20,729	(20,729)	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0.0000%	
HOMESTEAD	4,082	0	4,082	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	4,167	0	0	4,167	0.0178%	
HOMESTEAD (INT)	8,326	(8,326)	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0.0000%	
JEA (INT)	32,653	(32,653)	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0.0000%	
LCEC	791,723	0	791,723	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	808,230	0	0	808,230	3.4580%	
MOORE HAVEN	571	0	571	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	583	0	0	583	0.0025%	
NEW SMRYNA BCH	0	0	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0.0000%	
NEW SMYRNA BCH (INT)	0	0	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0.0000%	
NEW SMRYNA BCH (PEAK)	0	0	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0.0000%	
QUINCY	3,102	0	3,102	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	3,167	0	0	3,167	0.0135%	
WAUCHULA	1,878	0	1,878	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	1,917	0	0	1,917	0.0082%	
TOTAL WHOLESALE	1,046,022	(114,514)	931,507							950,929	0	0	950,929	4.0686%	
TOTAL FPL	22,136,360	(114,514)	22,021,845							1,285,116	521,339	21,566,071	23,372,526	100.0000%	
JURIS SEPARATION FACTOR														**0.959314**	

FLORIDA POWER & LIGHT
JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
E103INT - INTERMEDIATE STRATA PRODUCTION (CONTRACT ADJUSTED): 12CP Demand
December 2022 - Test Year

RATE CLASS	12 CP - KW			VOLTAGE LEVEL % - DEMAND			LOSS EXPANSION FACTORS			12 CP @ GENERATION - KW					% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	ADJUSTED	SYSTEM	RETAIL
CILC-1D	338,111	0	338,111	0.0000	0.4237	0.5763	1.0208	1.0355	1.0645	0	148,343	207,424	355,767	355,767	1.5142%	1.5867%
CILC-1G	15,748	0	15,748	0.0000	0.0180	0.9820	1.0208	1.0355	1.0645	0	293	16,462	16,756	16,756	0.0713%	0.0747%
CILC-1T	184,861	0	184,861	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	188,715	0	0	188,715	188,715	0.8032%	0.8417%
GS(T)-1	1,599,867	0	1,599,867	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	1,703,043	1,703,043	1,703,043	7.2483%	7.5955%
GSCU-1	8,298	0	8,298	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	8,833	8,833	8,833	0.0376%	0.0394%
GSD(T)-1	4,574,458	0	4,574,458	0.0000	0.0035	0.9965	1.0208	1.0355	1.0645	0	16,473	4,852,533	4,869,006	4,869,006	20.7230%	21.7157%
GSLD(T)-1	1,687,046	0	1,687,046	0.0000	0.0585	0.9415	1.0208	1.0355	1.0645	0	102,180	1,690,807	1,792,986	1,792,986	7.6311%	7.9967%
GSLD(T)-2	536,952	0	536,952	0.0000	0.4306	0.5694	1.0208	1.0355	1.0645	0	239,452	325,432	564,884	564,884	2.4042%	2.5194%
GSLD(T)-3	130,551	0	130,551	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	133,273	0	0	133,273	133,273	0.5672%	0.5944%
MET	12,921	0	12,921	0.0000	1.0000	0.0000	1.0208	1.0355	1.0645	0	13,380	0	13,380	13,380	0.0569%	0.0597%
OL-1	0	0	0	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	0	0	0	0.0000%	0.0000%
OS-2	1,068	0	1,068	0.0000	1.0000	0.0000	1.0208	1.0355	1.0645	0	1,106	0	1,106	1,106	0.0047%	0.0049%
RS(T)-1	11,983,542	0	11,983,542	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	12,756,366	12,756,366	12,756,366	54.2925%	56.8932%
SL-1	0	0	0	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	0	0	0	0.0000%	0.0000%
SL-1M	114	0	114	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	122	122	122	0.0005%	0.0005%
SL-2	4,499	0	4,499	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	4,789	4,789	4,789	0.0204%	0.0214%
SL-2M	244	0	244	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	260	260	260	0.0011%	0.0012%
SST-DST	109	0	109	0.0000	1.0000	0.0000	1.0208	1.0355	1.0645	0	112	0	112	112	0.0005%	0.0005%
SST-TST	11,950	0	11,950	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	12,199	0	0	12,199	12,199	0.0519%	0.0544%
TOTAL RETAIL	21,090,338	0	21,090,338							334,187	521,339	21,566,071	22,421,597	22,421,597	95.4287%	100.0000%
FKEC	130,152	0	130,152	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	132,866	0	0	132,866	132,866	0.5655%	
FPUC (INT)	12,721	0	12,721	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	12,986	0	0	12,986	**18,631**	0.0793%	
FPUC (PEAK)	9,719	(9,719)	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0	0.0000%	
G - FPU (INT)	30,367	0	30,367	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	31,000	0	0	31,000	**44,476**	0.1893%	
G - FPU (PEAK)	20,729	(20,729)	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0	0.0000%	
HOMESTEAD	4,082	0	4,082	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	4,167	0	0	4,167	4,167	0.0177%	
HOMESTEAD (INT)	8,326	0	8,326	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	8,500	0	0	8,500	**12,195**	0.0519%	
JEA (INT)	32,653	0	32,653	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	33,333	0	0	33,333	**47,823**	0.2035%	
LCEC	791,723	0	791,723	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	808,230	0	0	808,230	808,230	3.4399%	
MOORE HAVEN	571	0	571	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	583	0	0	583	583	0.0025%	
NEW SMRYNA BCH	0	0	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0	0.0000%	
NEW SMYRNA BCH (INT)	0	0	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0	0.0000%	
NEW SMRYNA BCH (PEAK)	0	0	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0	0.0000%	
QUINCY	3,102	0	3,102	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	3,167	0	0	3,167	3,167	0.0135%	
WAUCHULA	1,878	0	1,878	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	1,917	0	0	1,917	1,917	0.0082%	
TOTAL WHOLESALE	1,046,022	(30,448)	1,015,574							1,036,748	0	0	1,036,748	1,074,053	4.5713%	
TOTAL FPL	22,136,360	(30,448)	22,105,912							1,370,935	521,339	21,566,071	23,458,345	23,495,650	100.0000%	
JURIS SEPARATION FACTOR															**0.954287**	

FLORIDA POWER & LIGHT
JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
E103INT - INTERMEDIATE STRATA PRODUCTION (CONTRACT ADJUSTED): 12CP Demand
December 2022 - Test Year

RATE CLASS	12 CP - KW			VOLTAGE LEVEL % - DEMAND			LOSS EXPANSION FACTORS			12 CP @ GENERATION - KW					% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	ADJUSTED	SYSTEM	RETAIL

			FPUC (INT)	G - FPU (INT)	HOMESTEAD (INT)	JEA (INT)
Contract Adjusted 12CP @ Generation -	**Line No.**	**Source/Formula**	**Amount**	**Amount**	**Amount**	**Amount**
1) Contract Wholesale Customer 12 CP	1	oad Forecast * Loss Facto	12,986	31,000	8,500	33,333
2) Intermediate System Capacity Net of Reserve Margin	2					
Intermediate Summer Capacity	3	2020-2029 TYSP	19,652,000	19,652,000	19,652,000	19,652,000
Divide By: System Capacity Including Reserve Margin (Calculation)	4		120.0%	120.0%	120.0%	120.0%
Intermediate System Capacity Net of Reserve Margin	5	L3 / L4	16,376,667	16,376,667	16,376,667	16,376,667
Contract Wholesale Customer Contribution to Intermediate System Capacity Net of Reserve Margin	6	L1 / L5	0.000793	0.001893	0.000519	0.002035
3) Contract Adjusted 12CP @ Generation	7					
Total System 12CP Excluding All Stratified Contracts	8		23,372,526	23,372,526	23,372,526	23,372,526
Contribution (Excluding Intermediate Stratified Contracts) to Other Production System Capacity Net of Reserve Margin	9	1 - Sum L6	0.99476	0.99476	0.99476	0.99476
Total System 12CP Including Intermediate Stratified Contracts	10	L8 / L9	23,495,650	23,495,650	23,495,650	23,495,650
Contract Adjusted 12CP @ Generation	11	L6 * L11	18,631	44,476	12,195	47,823

FLORIDA POWER & LIGHT
JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
E103PK - PEAKING STRATA PRODUCTION (CONTRACT ADJUSTED): 12CP Demand
December 2022 - Test Year

RATE CLASS	12 CP - KW			VOLTAGE LEVEL % - DEMAND			LOSS EXPANSION FACTORS			12 CP @ GENERATION - KW					% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	ADJUSTED	SYSTEM	RETAIL
CILC-1D	338,111	0	338,111	0.0000	0.4237	0.5763	1.0208	1.0355	1.0645	0	148,343	207,424	355,767	355,767	1.5103%	1.5867%
CILC-1G	15,748	0	15,748	0.0000	0.0180	0.9820	1.0208	1.0355	1.0645	0	293	16,462	16,756	16,756	0.0711%	0.0747%
CILC-1T	184,861	0	184,861	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	188,715	0	0	188,715	188,715	0.8011%	0.8417%
GS(T)-1	1,599,867	0	1,599,867	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	1,703,043	1,703,043	1,703,043	7.2297%	7.5955%
GSCU-1	8,298	0	8,298	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	8,833	8,833	8,833	0.0375%	0.0394%
GSD(T)-1	4,574,458	0	4,574,458	0.0000	0.0035	0.9965	1.0208	1.0355	1.0645	0	16,473	4,852,533	4,869,006	4,869,006	20.6698%	21.7157%
GSLD(T)-1	1,687,046	0	1,687,046	0.0000	0.0585	0.9415	1.0208	1.0355	1.0645	0	102,180	1,690,807	1,792,986	1,792,986	7.6116%	7.9967%
GSLD(T)-2	536,952	0	536,952	0.0000	0.4306	0.5694	1.0208	1.0355	1.0645	0	239,452	325,432	564,884	564,884	2.3980%	2.5194%
GSLD(T)-3	130,551	0	130,551	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	133,273	0	0	133,273	133,273	0.5658%	0.5944%
MET	12,921	0	12,921	0.0000	1.0000	0.0000	1.0208	1.0355	1.0645	0	13,380	0	13,380	13,380	0.0568%	0.0597%
OL-1	0	0	0	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	0	0	0	0.0000%	0.0000%
OS-2	1,068	0	1,068	0.0000	1.0000	0.0000	1.0208	1.0355	1.0645	0	1,106	0	1,106	1,106	0.0047%	0.0049%
RS(T)-1	11,983,542	0	11,983,542	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	12,756,366	12,756,366	12,756,366	54.1531%	56.8932%
SL-1	0	0	0	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	0	0	0	0.0000%	0.0000%
SL-1M	114	0	114	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	122	122	122	0.0005%	0.0005%
SL-2	4,499	0	4,499	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	4,789	4,789	4,789	0.0203%	0.0214%
SL-2M	244	0	244	0.0000	0.0000	1.0000	1.0208	1.0355	1.0645	0	0	260	260	260	0.0011%	0.0012%
SST-DST	109	0	109	0.0000	1.0000	0.0000	1.0208	1.0355	1.0645	0	112	0	112	112	0.0005%	0.0005%
SST-TST	11,950	0	11,950	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	12,199	0	0	12,199	12,199	0.0518%	0.0544%
TOTAL RETAIL	21,090,338	0	21,090,338							334,187	521,339	21,566,071	22,421,597	22,421,597	95.1837%	100.0000%
FKEC	130,152	0	130,152	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	132,866	0	0	132,866	132,866	0.5640%	
FPUC (INT)	12,721	(12,721)	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0	0.0000%	
FPUC (PEAK)	9,719	0	9,719	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	9,922	0	0	9,922	**58,606**	0.2488%	
G - FPU (INT)	30,367	(30,367)	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0	0.0000%	
G - FPU (PEAK)	20,729	0	20,729	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	21,161	0	0	21,161	**124,996**	0.5306%	
HOMESTEAD	4,082	0	4,082	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	4,167	0	0	4,167	4,167	0.0177%	
HOMESTEAD (INT)	8,326	(8,326)	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0	0.0000%	
JEA (INT)	32,653	(32,653)	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0	0.0000%	
LCEC	791,723	0	791,723	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	808,230	0	0	808,230	808,230	3.4311%	
MOORE HAVEN	571	0	571	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	583	0	0	583	583	0.0025%	
NEW SMRYNA BCH	0	0	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0	0.0000%	
NEW SMYRNA BCH (INT)	0	0	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0	0.0000%	
NEW SMRYNA BCH (PEAK)	0	0	0	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	0	0	0	0	0	0.0000%	
QUINCY	3,102	0	3,102	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	3,167	0	0	3,167	3,167	0.0134%	
WAUCHULA	1,878	0	1,878	1.0000	0.0000	0.0000	1.0208	1.0355	1.0645	1,917	0	0	1,917	1,917	0.0081%	
TOTAL WHOLESALE	1,046,022	(84,066)	961,955							982,011	0	0	982,011	1,134,531	4.8163%	
TOTAL FPL	22,136,360	(84,066)	22,052,293							1,316,199	521,339	21,566,071	23,403,608	23,556,128	100.0000%	
JURIS SEPARATION FACTOR															**0.951837**	

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Appendix II - 2022 ECRC Projections
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FLORIDA POWER & LIGHT
JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
E103PK - PEAKING STRATA PRODUCTION (CONTRACT ADJUSTED): 12CP Demand
December 2022 - Test Year

RATE CLASS	12 CP - KW			VOLTAGE LEVEL % - DEMAND			LOSS EXPANSION FACTORS			12 CP @ GENERATION - KW					% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	ADJUSTED	SYSTEM	RETAIL

Contract Adjusted 12CP @ Generation -	Line No.	Source/Formula	FPUC (PEAK) Amount	G - FPU (PEAK) Amount
1) Contract Wholesale Customer 12 CP	1	oad Forecast * Loss Fact	9,922	21,161
2) Peaking System Capacity Net of Reserve Margin	2			
Peaking Summer Capacity	3	2020-2029 TYSP	4,785,500	4,785,500
Divide By: System Capacity Including Reserve Margin (Calculation)	4		120.0%	120.0%
Peaking System Capacity Net of Reserve Margin	5	L3 / L4	3,987,917	3,987,917
Contract Wholesale Customer Contribution to Intermediate System Capacity Net of Reserve Margin	6	L1 / L5	0.00249	0.00531
3) Contract Adjusted 12CP @ Generation	7			
Total System 12CP Excluding All Stratified Contracts	8		23,372,526	23,372,526
Contribution (Excluding Peaking Stratified Contracts) to Other Production System Capacity Net of Reserve Margin	9	1 - Sum L6	0.99221	0.99221
Total System 12CP Including Intermediate Stratified Contracts	10	L8 / L9	23,556,128	23,556,128
Contract Adjusted 12CP @ Generation	11	L6 * L11	58,606	124,996

FLORIDA POWER & LIGHT
JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
E104 - DISTRIBUTION: Group Non-Coincident Peak (GNCP) Demand
December 2022 - Test Year

RATE CLASS	MAX GNCP	VOLTAGE LEVEL % - DEMAND		LOSS EXPANSION FACTORS		MAX GNCP @ GENERATION			% OF TOTAL	
	@ METER	PRIMARY	SECOND	PRIMARY	SECOND	PRIMARY	SECOND	TOTAL	SYSTEM	RETAIL
CILC-1D	365,677	0.4237	0.5763	1.0355	1.0645	160,438	224,335	384,773	1.4305%	1.4305%
CILC-1G	17,146	0.0180	0.9820	1.0355	1.0645	319	17,923	18,242	0.0678%	0.0678%
CILC-1T	215,303	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	0.0000%
GS(T)-1	1,826,197	0.0000	1.0000	1.0355	1.0645	0	1,943,969	1,943,969	7.2272%	7.2272%
GSCU-1	9,315	0.0000	1.0000	1.0355	1.0645	0	9,916	9,916	0.0369%	0.0369%
GSD(T)-1	5,074,617	0.0035	0.9965	1.0355	1.0645	18,274	5,383,096	5,401,370	20.0809%	20.0809%
GSLD(T)-1	1,948,749	0.0585	0.9415	1.0355	1.0645	118,030	1,953,093	2,071,124	7.6999%	7.6999%
GSLD(T)-2	582,880	0.4306	0.5694	1.0355	1.0645	259,934	353,267	613,201	2.2797%	2.2797%
GSLD(T)-3	167,370	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	0.0000%
MET	15,793	1.0000	0.0000	1.0355	1.0645	16,355	0	16,355	0.0608%	0.0608%
OL-1	24,408	0.0000	1.0000	1.0355	1.0645	0	25,982	25,982	0.0966%	0.0966%
OS-2	7,281	1.0000	0.0000	1.0355	1.0645	7,540	0	7,540	0.0280%	0.0280%
RS(T)-1	15,259,164	0.0000	1.0000	1.0355	1.0645	0	16,243,234	16,243,234	60.3882%	60.3882%
SL-1	121,913	0.0000	1.0000	1.0355	1.0645	0	129,775	129,775	0.4825%	0.4825%
SL-1M	7,342	0.0000	1.0000	1.0355	1.0645	0	7,816	7,816	0.0291%	0.0291%
SL-2	6,497	0.0000	1.0000	1.0355	1.0645	0	6,916	6,916	0.0257%	0.0257%
SL-2M	486	0.0000	1.0000	1.0355	1.0645	0	517	517	0.0019%	0.0019%
SST-DST	16,698	1.0000	0.0000	1.0355	1.0645	17,291	0	17,291	0.0643%	0.0643%
SST-TST	46,871	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	0.0000%
TOTAL RETAIL	25,713,708					598,180	26,299,841	26,898,021	100.0000%	100.0000%
FKEC	158,742	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	
FPUC (INT)	13,715	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	
FPUC (PEAK)	30,420	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	
G - FPU (INT)	30,368	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	
G - FPU (PEAK)	30,891	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	
HOMESTEAD	24,490	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	
HOMESTEAD (INT)	49,959	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	
JEA (INT)	195,916	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	
LCEC	1,011,459	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	
MOORE HAVEN	3,919	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	
NEW SMRYNA BCH	0	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	
NEW SMYRNA BCH (INT)	0	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	
NEW SMRYNA BCH (PEAK)	0	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	
QUINCY	18,613	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	
WAUCHULA	13,715	0.0000	0.0000	1.0355	1.0645	0	0	0	0.0000%	
TOTAL WHOLESALE	1,582,208					0	0	0	0.0000%	
TOTAL FPL	27,295,916					598,180	26,299,841	26,898,021	100.0000%	
JURIS SEPARATION FACTOR									**1.000000**	

FLORIDA POWER & LIGHT
JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
E201 - TOTAL SALES: Total Annual Energy
December 2022 - Test Year

RATE CLASS	MWH SALES	VOLTAGE LEVEL %			LOSS EXPANSION FACTORS			MWH SALES @ GENERATION				% OF TOTAL	
	@ METER	TRANS	PRIMARY	SECONDARY	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	SYSTEM	RETAIL
CILC-1D	2,535,287	0.0000	0.4171	0.5829	1.0164	1.0274	1.0491	0	1,086,378	1,550,459	2,636,837	1.9507%	2.0611%
CILC-1G	112,191	0.0000	0.0170	0.9830	1.0164	1.0274	1.0491	0	1,964	115,692	117,656	0.0870%	0.0920%
CILC-1T	1,504,497	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	1,529,183	0	0	1,529,183	1.1312%	1.1953%
GS(T)-1	8,368,517	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	8,779,240	8,779,240	6.4946%	6.8625%
GSCU-1	69,414	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	72,821	72,821	0.0539%	0.0569%
GSD(T)-1	28,295,907	0.0000	0.0037	0.9963	1.0164	1.0274	1.0491	0	106,198	29,576,223	29,682,421	21.9581%	23.2020%
GSLD(T)-1	10,335,975	0.0000	0.0574	0.9426	1.0164	1.0274	1.0491	0	609,862	10,220,553	10,830,415	8.0120%	8.4659%
GSLD(T)-2	3,825,387	0.0000	0.4313	0.5687	1.0164	1.0274	1.0491	0	1,695,115	2,282,319	3,977,434	2.9424%	3.1091%
GSLD(T)-3	960,789	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	976,554	0	0	976,554	0.7224%	0.7633%
MET	84,975	0.0000	1.0000	0.0000	1.0164	1.0274	1.0491	0	87,306	0	87,306	0.0646%	0.0682%
OL-1	90,638	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	95,087	95,087	0.0703%	0.0743%
OS-2	9,901	0.0000	1.0000	0.0000	1.0164	1.0274	1.0491	0	10,173	0	10,173	0.0075%	0.0080%
RS(T)-1	65,315,939	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	68,521,615	68,521,615	50.6902%	53.5616%
SL-1	452,711	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	474,930	474,930	0.3513%	0.3712%
SL-1M	26,569	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	27,873	27,873	0.0206%	0.0218%
SL-2	37,681	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	39,531	39,531	0.0292%	0.0309%
SL-2M	3,001	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	3,148	3,148	0.0023%	0.0025%
SST-DST	1,411	0.0000	1.0000	0.0000	1.0164	1.0274	1.0491	0	1,450	0	1,450	0.0011%	0.0011%
SST-TST	65,711	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	66,789	0	0	66,789	0.0494%	0.0522%
TOTAL RETAIL	122,096,501							2,572,525	3,598,445	121,759,492	127,930,462	94.6390%	100.0000%
FKEC	799,412	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	812,528	0	0	812,528	0.6011%	
FPUC (INT)	101,728	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	103,398	0	0	103,398	0.0765%	
FPUC (PEAK)	53,455	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	54,332	0	0	54,332	0.0402%	
G - FPU (INT)	181,040	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	184,010	0	0	184,010	0.1361%	
G - FPU (PEAK)	105,541	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	107,273	0	0	107,273	0.0794%	
HOMESTEAD	31,630	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	32,149	0	0	32,149	0.0238%	
HOMESTEAD (INT)	228,809	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	232,563	0	0	232,563	0.1720%	
JEA (INT)	1,061,600	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	1,079,019	0	0	1,079,019	0.7982%	
LCEC	4,363,325	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	4,434,918	0	0	4,434,918	3.2808%	
MOORE HAVEN	17,408	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	17,693	0	0	17,693	0.0131%	
NEW SMRYNA BCH	17,692	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	17,982	0	0	17,982	0.0133%	
NEW SMRYNA BCH (INT)	312	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	317	0	0	317	0.0002%	
NEW SMRYNA BCH (PEAK)	4,888	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	4,968	0	0	4,968	0.0037%	
QUINCY	99,134	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	100,761	0	0	100,761	0.0745%	
WAUCHULA	63,867	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	64,915	0	0	64,915	0.0480%	
TOTAL WHOLESALE	7,129,840							7,246,825	0	0	7,246,825	5.3610%	
TOTAL FPL	129,226,341							9,819,351	3,598,445	121,759,492	135,177,288	100.0000%	
JURIS SEPARATION FACTOR												**0.946390**	

FLORIDA POWER & LIGHT
JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
E202 - NON-STRATIFIED SALES: Total Annual Energy
December 2022 - Test Year

RATE CLASS	MWH SALES			VOLTAGE LEVEL %			LOSS EXPANSION FACTORS			MWH SALES @ GENERATION				% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECONDARY	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	SYSTEM	RETAIL
CILC-1D	2,535,287	0	2,535,287	0.0000	0.4171	0.5829	1.0164	1.0274	1.0491	0	1,086,378	1,550,459	2,636,837	1.9765%	2.0611%
CILC-1G	112,191	0	112,191	0.0000	0.0170	0.9830	1.0164	1.0274	1.0491	0	1,964	115,692	117,656	0.0882%	0.0920%
CILC-1T	1,504,497	0	1,504,497	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	1,529,183	0	0	1,529,183	1.1462%	1.1953%
GS(T)-1	8,368,517	0	8,368,517	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	8,779,240	8,779,240	6.5806%	6.8625%
GSCU-1	69,414	0	69,414	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	72,821	72,821	0.0546%	0.0569%
GSD(T)-1	28,295,907	0	28,295,907	0.0000	0.0037	0.9963	1.0164	1.0274	1.0491	0	106,198	29,576,223	29,682,421	22.2488%	23.2020%
GSLD(T)-1	10,335,975	0	10,335,975	0.0000	0.0574	0.9426	1.0164	1.0274	1.0491	0	609,862	10,220,553	10,830,415	8.1181%	8.4659%
GSLD(T)-2	3,825,387	0	3,825,387	0.0000	0.4313	0.5687	1.0164	1.0274	1.0491	0	1,695,115	2,282,319	3,977,434	2.9813%	3.1091%
GSLD(T)-3	960,789	0	960,789	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	976,554	0	0	976,554	0.7320%	0.7633%
MET	84,975	0	84,975	0.0000	1.0000	0.0000	1.0164	1.0274	1.0491	0	87,306	0	87,306	0.0654%	0.0682%
OL-1	90,638	0	90,638	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	95,087	95,087	0.0713%	0.0743%
OS-2	9,901	0	9,901	0.0000	1.0000	0.0000	1.0164	1.0274	1.0491	0	10,173	0	10,173	0.0076%	0.0080%
RS(T)-1	65,315,939	0	65,315,939	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	68,521,615	68,521,615	51.3611%	53.5616%
SL-1	452,711	0	452,711	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	474,930	474,930	0.3560%	0.3712%
SL-1M	26,569	0	26,569	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	27,873	27,873	0.0209%	0.0218%
SL-2	37,681	0	37,681	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	39,531	39,531	0.0296%	0.0309%
SL-2M	3,001	0	3,001	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	3,148	3,148	0.0024%	0.0025%
SST-DST	1,411	0	1,411	0.0000	1.0000	0.0000	1.0164	1.0274	1.0491	0	1,450	0	1,450	0.0011%	0.0011%
SST-TST	65,711	0	65,711	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	66,789	0	0	66,789	0.0501%	0.0522%
TOTAL RETAIL	122,096,501	0	122,096,501							2,572,525	3,598,445	121,759,492	127,930,462	95.8917%	100.0000%
FKEC	799,412	0	799,412	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	812,528	0	0	812,528	0.6090%	
FPUC (INT)	101,728	(101,728)	0	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	0	0	0	0	0.0000%	
FPUC (PEAK)	53,455	(53,455)	0	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	0	0	0	0	0.0000%	
G - FPU (INT)	181,040	(181,040)	0	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	0	0	0	0	0.0000%	
G - FPU (PEAK)	105,541	(105,541)	0	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	0	0	0	0	0.0000%	
HOMESTEAD	31,630	0	31,630	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	32,149	0	0	32,149	0.0241%	
HOMESTEAD (INT)	228,809	(228,809)	0	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	0	0	0	0	0.0000%	
JEA (INT)	1,061,600	(1,061,600)	0	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	0	0	0	0	0.0000%	
LCEC	4,363,325	0	4,363,325	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	4,434,918	0	0	4,434,918	3.3242%	
MOORE HAVEN	17,408	0	17,408	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	17,693	0	0	17,693	0.0133%	
NEW SMRYNA BCH	17,692	0	17,692	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	17,982	0	0	17,982	0.0135%	
NEW SMRYNA BCH (PEAK)	4,888	(4,888)	0	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	0	0	0	0	0.0000%	
NEW SMYRNA BCH (INT)	312	(312)	0	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	0	0	0	0	0.0000%	
QUINCY	99,134	0	99,134	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	100,761	0	0	100,761	0.0755%	
WAUCHULA	63,867	0	63,867	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	64,915	0	0	64,915	0.0487%	
TOTAL WHOLESALE	7,129,840	(1,737,372)	5,392,467							5,480,946	0	0	5,480,946	4.1083%	
TOTAL FPL	129,226,341	(1,737,372)	127,488,969							8,053,472	3,598,445	121,759,492	133,411,409	100.0000%	
JURIS SEPARATION FACTOR														**0.958917**	

FLORIDA POWER & LIGHT
JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
E203INT - INTERMEDIATE STRATA SALES (CONTRACT ADJUSTED): Total Annual Energy
December 2022 - Test Year

RATE CLASS	MWH SALES			VOLTAGE LEVEL %			LOSS EXPANSION FACTORS			MWH SALES @ GENERATION				% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECONDARY	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	SYSTEM	RETAIL
CILC-1D	2,535,287	0	2,535,287	0.0000	0.4171	0.5829	1.0164	1.0274	1.0491	0	1,086,378	1,550,459	2,636,837	1.9531%	2.0611%
CILC-1G	112,191	0	112,191	0.0000	0.0170	0.9830	1.0164	1.0274	1.0491	0	1,964	115,692	117,656	0.0871%	0.0920%
CILC-1T	1,504,497	0	1,504,497	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	1,529,183	0	0	1,529,183	1.1326%	1.1953%
GS(T)-1	8,368,517	0	8,368,517	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	8,779,240	8,779,240	6.5026%	6.8625%
GSCU-1	69,414	0	69,414	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	72,821	72,821	0.0539%	0.0569%
GSD(T)-1	28,295,907	0	28,295,907	0.0000	0.0037	0.9963	1.0164	1.0274	1.0491	0	106,198	29,576,223	29,682,421	21.9852%	23.2020%
GSLD(T)-1	10,335,975	0	10,335,975	0.0000	0.0574	0.9426	1.0164	1.0274	1.0491	0	609,862	10,220,553	10,830,415	8.0219%	8.4659%
GSLD(T)-2	3,825,387	0	3,825,387	0.0000	0.4313	0.5687	1.0164	1.0274	1.0491	0	1,695,115	2,282,319	3,977,434	2.9460%	3.1091%
GSLD(T)-3	960,789	0	960,789	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	976,554	0	0	976,554	0.7233%	0.7633%
MET	84,975	0	84,975	0.0000	1.0000	0.0000	1.0164	1.0274	1.0491	0	87,306	0	87,306	0.0647%	0.0682%
OL-1	90,638	0	90,638	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	95,087	95,087	0.0704%	0.0743%
OS-2	9,901	0	9,901	0.0000	1.0000	0.0000	1.0164	1.0274	1.0491	0	10,173	0	10,173	0.0075%	0.0080%
RS(T)-1	65,315,939	0	65,315,939	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	68,521,615	68,521,615	50.7527%	53.5616%
SL-1	452,711	0	452,711	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	474,930	474,930	0.3518%	0.3712%
SL-1M	26,569	0	26,569	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	27,873	27,873	0.0206%	0.0218%
SL-2	37,681	0	37,681	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	39,531	39,531	0.0293%	0.0309%
SL-2M	3,001	0	3,001	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	3,148	3,148	0.0023%	0.0025%
SST-DST	1,411	0	1,411	0.0000	1.0000	0.0000	1.0164	1.0274	1.0491	0	1,450	0	1,450	0.0011%	0.0011%
SST-TST	65,711	0	65,711	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	66,789	0	0	66,789	0.0495%	0.0522%
TOTAL RETAIL	122,096,501	0	122,096,501							2,572,525	3,598,445	121,759,492	127,930,462	94.7558%	100.0000%
FKEC	799,412	0	799,412	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	812,528	0	0	812,528	0.6018%	
FPUC (INT)	101,728	0	101,728	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	103,398	0	0	103,398	0.0766%	
FPUC (PEAK)	53,455	(53,455)	0	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	0	0	0	0	0.0000%	
G - FPU (INT)	181,040	0	181,040	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	184,010	0	0	184,010	0.1363%	
G - FPU (PEAK)	105,541	(105,541)	0	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	0	0	0	0	0.0000%	
HOMESTEAD	31,630	0	31,630	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	32,149	0	0	32,149	0.0238%	
HOMESTEAD (INT)	228,809	0	228,809	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	232,563	0	0	232,563	0.1723%	
JEA (INT)	1,061,600	0	1,061,600	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	1,079,019	0	0	1,079,019	0.7992%	
LCEC	4,363,325	0	4,363,325	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	4,434,918	0	0	4,434,918	3.2849%	
MOORE HAVEN	17,408	0	17,408	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	17,693	0	0	17,693	0.0131%	
NEW SMRYNA BCH	17,692	0	17,692	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	17,982	0	0	17,982	0.0133%	
NEW SMYRNA BCH (INT)	312	0	312	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	317	0	0	317	0.0002%	
NEW SMRYNA BCH (PEAK)	4,888	(4,888)	0	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	0	0	0	0	0.0000%	
QUINCY	99,134	0	99,134	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	100,761	0	0	100,761	0.0746%	
WAUCHULA	63,867	0	63,867	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	64,915	0	0	64,915	0.0481%	
TOTAL WHOLESALE	7,129,840	(163,883)	6,965,957							7,080,253	0	0	7,080,253	5.2442%	
TOTAL FPL	129,226,341	(163,883)	129,062,458							9,652,779	3,598,445	121,759,492	135,010,716	100.0000%	
JURIS SEPARATION FACTOR														0.947558	

FLORIDA POWER & LIGHT
JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
E203PK - PEAKING STRATA SALES (CONTRACT ADJUSTED): Total Annual Energy
December 2022 - Test Year

RATE CLASS	MWH SALES			VOLTAGE LEVEL %			LOSS EXPANSION FACTORS			MWH SALES @ GENERATION				% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECONDARY	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	SYSTEM	RETAIL
CILC-1D	2,535,287	0	2,535,287	0.0000	0.4171	0.5829	1.0164	1.0274	1.0491	0	1,086,378	1,550,459	2,636,837	1.9740%	2.0611%
CILC-1G	112,191	0	112,191	0.0000	0.0170	0.9830	1.0164	1.0274	1.0491	0	1,964	115,692	117,656	0.0881%	0.0920%
CILC-1T	1,504,497	0	1,504,497	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	1,529,183	0	0	1,529,183	1.1448%	1.1953%
GS(T)-1	8,368,517	0	8,368,517	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	8,779,240	8,779,240	6.5724%	6.8625%
GSCU-1	69,414	0	69,414	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	72,821	72,821	0.0545%	0.0569%
GSD(T)-1	28,295,907	0	28,295,907	0.0000	0.0037	0.9963	1.0164	1.0274	1.0491	0	106,198	29,576,223	29,682,421	22.2210%	23.2020%
GSLD(T)-1	10,335,975	0	10,335,975	0.0000	0.0574	0.9426	1.0164	1.0274	1.0491	0	609,862	10,220,553	10,830,415	8.1079%	8.4659%
GSLD(T)-2	3,825,387	0	3,825,387	0.0000	0.4313	0.5687	1.0164	1.0274	1.0491	0	1,695,115	2,282,319	3,977,434	2.9776%	3.1091%
GSLD(T)-3	960,789	0	960,789	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	976,554	0	0	976,554	0.7311%	0.7633%
MET	84,975	0	84,975	0.0000	1.0000	0.0000	1.0164	1.0274	1.0491	0	87,306	0	87,306	0.0654%	0.0682%
OL-1	90,638	0	90,638	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	95,087	95,087	0.0712%	0.0743%
OS-2	9,901	0	9,901	0.0000	1.0000	0.0000	1.0164	1.0274	1.0491	0	10,173	0	10,173	0.0076%	0.0080%
RS(T)-1	65,315,939	0	65,315,939	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	68,521,615	68,521,615	51.2971%	53.5616%
SL-1	452,711	0	452,711	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	474,930	474,930	0.3555%	0.3712%
SL-1M	26,569	0	26,569	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	27,873	27,873	0.0209%	0.0218%
SL-2	37,681	0	37,681	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	39,531	39,531	0.0296%	0.0309%
SL-2M	3,001	0	3,001	0.0000	0.0000	1.0000	1.0164	1.0274	1.0491	0	0	3,148	3,148	0.0024%	0.0025%
SST-DST	1,411	0	1,411	0.0000	1.0000	0.0000	1.0164	1.0274	1.0491	0	1,450	0	1,450	0.0011%	0.0011%
SST-TST	65,711	0	65,711	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	66,789	0	0	66,789	0.0500%	0.0522%
TOTAL RETAIL	122,096,501	0	122,096,501							2,572,525	3,598,445	121,759,492	127,930,462	95.7721%	100.0000%
FKEC	799,412	0	799,412	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	812,528	0	0	812,528	0.6083%	
FPUC (INT)	101,728	(101,728)	0	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	0	0	0	0	0.0000%	
FPUC (PEAK)	53,455	0	53,455	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	54,332	0	0	54,332	0.0407%	
G - FPU (INT)	181,040	(181,040)	0	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	0	0	0	0	0.0000%	
G - FPU (PEAK)	105,541	0	105,541	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	107,273	0	0	107,273	0.0803%	
HOMESTEAD	31,630	0	31,630	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	32,149	0	0	32,149	0.0241%	
HOMESTEAD (INT)	228,809	(228,809)	0	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	0	0	0	0	0.0000%	
JEA (INT)	1,061,600	(1,061,600)	0	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	0	0	0	0	0.0000%	
LCEC	4,363,325	0	4,363,325	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	4,434,918	0	0	4,434,918	3.3201%	
MOORE HAVEN	17,408	0	17,408	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	17,693	0	0	17,693	0.0132%	
NEW SMRYNA BCH	17,692	0	17,692	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	17,982	0	0	17,982	0.0135%	
NEW SMRYNA BCH (INT)	312	(312)	0	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	0	0	0	0	0.0000%	
NEW SMRYNA BCH (PEAK)	4,888	0	4,888	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	4,968	0	0	4,968	0.0037%	
QUINCY	99,134	0	99,134	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	100,761	0	0	100,761	0.0754%	
WAUCHULA	63,867	0	63,867	1.0000	0.0000	0.0000	1.0164	1.0274	1.0491	64,915	0	0	64,915	0.0486%	
TOTAL WHOLESALE	7,129,840	(1,573,489)	5,556,350							5,647,518	0	0	5,647,518	4.2279%	
TOTAL FPL	129,226,341	(1,573,489)	127,652,852							8,220,044	3,598,445	121,759,492	133,577,980	100.0000%	
JURISDICTIONAL SEPARATION FACTOR														**0.957721**	

FLORIDA POWER & LIGHT
JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
SEP - Internals Based on Externals (B2S)
December 2022 - Test Year

SEP - INTERNAL FACTORS BASED ON EXTERNAL FACTORS	ALLOCATOR	COMPANY PER BOOKS	SEPARATION FACTOR	JURISDICTONAL	INTERNAL SEPARATION FACTOR
I900-LABOR-EXC-A&G					
L_INC100000 - STEAM O&M PAY - OPERAT SUPERV & ENG	BLENDED	1,153,822	0.958418	1,105,843	
L_INC101210 - STEAM O&M PAY - FUEL - NON RECOVERABLE OIL	BLENDED	164,993	0.953661	157,347	
L_INC102000 - STEAM O&M PAY - STEAM EXPENSES	BLENDED	2,376,106	0.959293	2,279,382	
L_INC105000 - STEAM O&M PAY - ELECTRIC EXPENSES	BLENDED	1,817,598	0.959284	1,743,591	
L_INC106000 - STEAM O&M PAY - MISC STEAM POWER EXPENSES	BLENDED	5,840,834	0.957388	5,591,944	
L_INC110000 - STEAM O&M PAY - MAINT SUPERV & ENG	BLENDED	1,035,263	0.958023	991,806	
L_INC111000 - STEAM O&M PAY - MAINT OF STRUCTURES	BLENDED	1,588,766	0.958673	1,523,106	
L_INC112000 - STEAM O&M PAY - MAINT OF BOILER PLANT	BLENDED	2,625,296	0.958172	2,515,484	
L_INC113000 - STEAM O&M PAY - MAINT OF ELECTRIC PLANT	BLENDED	1,275,054	0.955628	1,218,478	
L_INC114000 - STEAM O&M PAY - MAINT OF MISC STEAM PLT	BLENDED	575,362	0.958894	551,712	
L_INC117000 - NUCLEAR O&M PAY - OPER SUPERV & ENG	BLENDED	44,383,699	0.959454	42,584,109	
L_INC119000 - NUCLEAR O&M PAY - COOLANTS AND WATER	BLENDED	3,150,377	0.959647	3,023,250	
L_INC120000 - NUCLEAR O&M PAY - STEAM EXPENSES	BLENDED	44,301,329	0.959491	42,506,743	
L_INC123000 - NUCLEAR O&M PAY - ELECTRIC EXP	BLENDED	453	0.959307	434	
L_INC124000 - NUCLEAR O&M PAY - MISC NUCLEAR POWER EXP	BLENDED	33,952,424	0.958782	32,552,981	
L_INC128000 - NUCLEAR O&M PAY - MAINT SUPERVISION & ENGINEERING	BLENDED	197,627,071	0.959125	189,549,048	
L_INC129000 - NUCLEAR O&M PAY - MAINT OF STRUCTURES	BLENDED	163,170	0.959371	156,541	
L_INC130000 - NUCLEAR O&M PAY - MAINT OF REACTOR PLANT	BLENDED	75,875	0.960488	72,877	
L_INC131000 - NUCLEAR O&M PAY - MAINT OF ELECTRIC PLANT	BLENDED	539,172	0.959799	517,497	
L_INC132000 - NUCLEAR O&M PAY - MAINT OF MISC NUCLEAR PLANT	BLENDED	1,314	0.960592	1,263	
L_INC146000 - OTH PWR O&M PAY - OPERAT SUPERV & ENG	BLENDED	13,594,628	0.955052	12,983,578	
L_INC147200 - OTH PWR O&M PAY - FUEL N- RECOV EMISSIONS FEE	BLENDED	3,455,295	0.946412	3,270,134	
L_INC148000 - OTH PWR O&M PAY- GENERATION EXPENSES	BLENDED	10,164,639	0.954839	9,705,590	
L_INC149000 - OTH PWR O&M PAY - MISC OTHER POWER GENERATION EXPENSES	BLENDED	22,521,800	0.955252	21,513,987	
L_INC151000 - OTH PWR O&M PAY - MAINT SUPERV & ENG	BLENDED	8,603,614	0.952225	8,192,574	
L_INC152000 - OTH PWR O&M PAY - MAINT OF STRUCTURES	BLENDED	20,897,041	0.954161	19,939,149	
L_INC153000 - OTH PWR O&M PAY - MAINT GENERATING & ELECTRIC PLANT	BLENDED	16,551,151	0.948211	15,693,980	
L_INC154000 - OTH PWR O&M PAY - MAINT MISC OTHER PWR GENERAT	BLENDED	3,278,434	0.949195	3,111,873	
L_INC156000 - OTH PWR O&M PAY - SYSTEM CONTROL & LOAD DISPATCH	I340	868,289	0.955404	829,566	
L_INC157000 - OTH PWR O&M PAY - OTHER EXPENSES LOC 955	I340	1,511,611	0.955404	1,444,198	
L_INC260010 - TRANS O&M PAY - OPERATION SUPERV & ENGINEERING	E101	4,959,832	0.902581	4,476,649	
L_INC261000 - TRANS O&M PAY - LOAD DISPATCHING	E101	3,086,033	0.902581	2,785,394	
L_INC262000 - TRANS O&M PAY - STATION EXPENSES	E101	1,241,846	0.902581	1,120,866	
L_INC263000 - TRANS O&M PAY - OVERHEAD LINE EXPENSES	E101	61,150	0.902581	55,192	
L_INC266000 - TRANS O&M PAY - MISC TRANSMISSION EXPENSES	E101	3,961,791	0.902581	3,575,836	
L_INC268010 - TRANS O&M PAY - MAINT SUPERV & ENG	E101	1,964,589	0.902581	1,773,200	
L_INC269000 - TRANS O&M PAY - MAINT OF STRUCTURES	E101	3,239,591	0.902581	2,923,992	
L_INC270000 - TRANS O&M PAY - MAINT OF STATION EQ	E101	1,467,189	0.902581	1,324,256	
L_INC271000 - TRANS O&M PAY - MAINT OF OVERHEAD LINES	E101	1,366,419	0.902581	1,233,304	
L_INC272000 - TRANS O&M PAY - MAINT UNDERGROUND LINES	E101	16,452	0.902581	14,850	
L_INC380000 - DIST O&M PAY - OPERATION SUPERVISION AND ENGINEERING	E104	25,026,141	1.000000	25,026,141	
L_INC381000 - DIST O&M PAY - LOAD DISPATCHING	E104	4,523,619	1.000000	4,523,619	
L_INC382000 - DIST O&M PAY - SUBSTATION EXPENSES	E104	814,990	1.000000	814,990	
L_INC383000 - DIST O&M PAY - OVERHEAD LINE EXPENSES	I365T	4,971,521	1.000000	4,971,521	
L_INC384000 - DIST O&M PAY - UNDERGROUND LINE EXP	I367T	1,622,213	1.000000	1,622,213	
L_INC385000 - DIST O&M PAY - STREET LIGHTING AND SIGNAL SYSTEM EXPENSES	E508	1,752,435	1.000000	1,752,435	
L_INC386000 - DIST O&M PAY - METER EXPENSES	E325	(947,124)	0.996349	(943,666)	
L_INC387000 - DIST O&M PAY - CUSTOMER INSTALLATIONS EXP	E309	1,116,576	1.000000	1,116,576	
L_INC388000 - DIST O&M PAY - MISC DISTRIBUTION EXPENSES	E104	26,519,128	1.000000	26,519,128	
L_INC390000 - DIST O&M PAY - MAINT SUPERV & ENG	E104	16,712,775	1.000000	16,712,775	
L_INC391000 - DIST O&M PAY - MAINT OF STRUCTURES	E104	1,984	1.000000	1,984	
L_INC392000 - DIST O&M PAY - MAINT OF STATION EQ	E104	3,110,512	1.000000	3,110,512	
L_INC393000 - DIST O&M PAY - MAINT OF OVERHEAD LINES	I365T	24,700,469	1.000000	24,700,469	
L_INC394000 - DIST O&M PAY - MAINT UNDERGROUND LINES	I367T	10,499,962	1.000000	10,499,962	
L_INC395000 - DIST O&M PAY - MAINT OF LINE TRANSFORMERS	E104	18,268	1.000000	18,268	
L_INC396000 - DIST O&M PAY - MAINT OF STREET LIGHTING & SIGNAL SYSTEMS	E508	4,208,675	1.000000	4,208,675	
L_INC397000 - DIST O&M PAY - MAINT OF METERS	E325	3,605,912	0.996349	3,592,747	
L_INC398000 - DIST O&M PAY - MAINT OF MISC DISTRI PLT	E104	17,274	1.000000	17,274	
L_INC401000 - CUST ACCT O&M PAY - SUPERVISION	I540	5,570,046	0.999978	5,569,923	
L_INC402000 - CUST ACCT O&M PAY - METER READING EXP	E330	14,936,781	0.999995	14,936,705	
L_INC403000 - CUST ACCT O&M PAY - CUST REC & COLLECT	E356	41,341,974	1.000000	41,341,974	
L_INC407000 - CUST SERV & INFO PAY - SUPERVISION	E356	124,688	1.000000	124,688	
L_INC408000 - CUST SERV & INFO PAY - CUST ASSIST EXP	E356	11,093,092	1.000000	11,093,092	
L_INC409000 - CUST SERV & INFO PAY - INFO & INST ADV - GENERAL	E356	2,067	1.000000	2,067	
L_INC410000 - CUST SERV & INFO PAY - MISC CUST SERV & INF	E356	5,226,321	1.000000	5,226,321	
L_INC510000 - DEMONSTRATING AND SELLING EXPENSES	E356	235,560	1.000000	235,560	
L_INC516000 - MISC AND SELLING EXPENSES	E356	578,265	1.000000	578,265	
Total I900-LABOR-EXC-A&G		672,843,496		651,985,828	**0.969001**

MIAMI-DADE COUNTY, through its
DEPARTMENT OF REGULATORY AND
ECONOMIC RESOURCES, DIVISION OF
ENVIRONMENTAL RESOURCES
MANAGEMENT,

Complainant,

CONSENT AGREEMENT

v.

FLORIDA POWER & LIGHT COMPANY,

Respondent.
_______________________________________/

This Consent Agreement, entered into by and between the Complainant, MIAMI-DADE COUNTY, through its DEPARTMENT OF REGULATORY AND ECONOMIC RESOURCES, DIVISION OF ENVIRONMENTAL RESOURCES MANAGEMENT ("DERM"), and the Respondent FLORIDA POWER & LIGHT COMPANY ("FPL"), pursuant to Section 24-7(15)(c) of the Code of Miami-Dade County, shall serve to redress alleged violations of Chapter 24 of the Code of Miami-Dade County located near, surrounding, or in the vicinity of the Cooling Canal System located at Turkey Point on FPL's property, as further described herein, in Miami-Dade County, Florida.

DERM and FPL enter into the following Consent Agreement:

FINDINGS OF FACT

1. DERM is a division of Miami-Dade County, a political subdivision of the State of Florida, which is empowered to control and prohibit pollution and protect the environment within Miami-Dade County pursuant to Article VIII, Section 6 of the Florida Constitution, the Miami-Dade County Home Rule Charter and Section 403.182 of the Florida Statutes.

2. Florida Power & Light Company ("FPL") is the owner and operator of the Turkey Point Power Plant, and FPL is the owner and operator of approximately a 5,900-acre network of unlined canals (the "Cooling Canal System" or "CCS") on the FPL property described in the map in Exhibit A (the "Property").

3. In 1971, FPL signed a Consent Decree with the U.S. Department of Justice that required the construction, after permitting, of a closed-loop cooling configuration, with no discharge to surface waters.

4. The Florida Department of Pollution Control (later to become the Florida Department of Environmental Protection), in 1971, issued Construction Permit No. IC-1286 for the CCS. In 1972, Dade County issued Zoning Use Permit No. W-49833 for the excavation of the proposed Alternate Cooling Water Return Canal. FPL represents that in 1973, the construction of the CCS was completed; and the CCS was closed from the surface waters of both Biscayne Bay and Card Sound, becoming a closed-loop system.

5. An approximate 18 foot deep interceptor ditch located along the west side of the CCS was designed and constructed to create a hydraulic barrier to keep water in the CCS from migrating inland or westward.

6. In 1972, FPL entered into an agreement with the Central and Southern Florida Flood Control District (later to become the South Florida Water Management District or "District") addressing the operations and impacts of the CCS. The agreement has been updated several times, with the most recent version being the Fifth Supplemental Agreement between the District and FPL entered into on October 16, 2009 ("Fifth Supplemental Agreement") which included an extensive monitoring program for the CCS, entitled the Turkey Point Plant Groundwater, Surface Water and Ecological Monitoring Plan ("2009 Monitoring Plan"), incorporated as Exhibit A of the Fifth Supplemental Agreement.

7. In a letter dated April 16, 2013, the District notified FPL of their determination that saline water from the CCS has moved westward of the L-31E Canal in excess of those amounts that would have occurred without the existence of the CCS, and pursuant to the provisions of the Fifth Supplemental Agreement, initiated consultation with FPL for the mitigation, abatement or remediation of the saline water movement.

8. DERM issued a Notice of Violation dated October 2, 2015 (the "NOV") to FPL, alleging violations of Chapter 24 of the Code of Miami-Dade County, for alleged violations of County water quality standards and criteria in groundwater attributable to FPL's actions, and specifically for groundwaters outside the boundaries of FPL's Cooling Canal System and beyond the boundaries of the Property.

9. The phrase "hypersaline water" as used herein is defined as water that exceeds 19,000 mg/L chlorides.

10. DERM maintains there is hypersaline water attributable to FPL's actions in the groundwaters outside the boundaries of the Property, which exceeds County water quality standards and criteria. FPL acknowledges the presence of hypersaline water in certain areas outside the boundaries of the Property. For waters that do not reach the level of hypersalinity, DERM and FPL do not agree on the applicable "background" standards for chlorides.

11. In 2013 and 2014, FPL experienced water quality issues within the CCS, including increases in temperature and salinity, and FPL sought approvals from various regulatory agencies for actions to improve the water quality within the CCS.

12. DEP issued an Administrative Order, No. 14-0741, on December 23, 2014, requiring FPL to, among other things, reduce and maintain the annual average salinity of the CCS at a practical salinity of 34, and that Administrative Order is currently the subject of an Administrative Hearing.

13. Both DERM and FPL agree and acknowledge that it would be beneficial to improve the water quality within the Cooling Canal System itself, and FPL has already undertaken some efforts to improve the CCS water quality.

14. This Consent Agreement requires FPL to take action to address the County's alleged violations of County water quality standards and criteria in groundwaters outside the CCS as described in the NOV. As part of these actions, this Consent Agreement also requires FPL to take into account its efforts to improve CCS water quality and the potential and actual impacts of such actions on water resources outside the CCS, to not cause or contribute to (i) the exacerbation of alleged violations of County water quality standards or criteria or (ii) future violations of County water quality standards or criteria in the groundwaters or surface waters outside the CCS.

15. FPL hereby agrees to the terms of this Consent Agreement without admitting the allegations made by the above-mentioned NOV.

16. In an effort to expeditiously resolve this matter and to ensure compliance with Chapter 24 of the Code of Miami-Dade County, and to avoid time consuming and costly litigation, the parties hereto agree to the following, and it is ORDERED:

REQUIREMENTS

17. FPL shall undertake the following activities to specifically address water quality impacts associated with the CCS, as alleged in the NOV. The objective of this Consent Agreement will be for FPL to demonstrate a statistically valid reduction in the salt mass and volumetric extent of hypersaline water (as represented by chloride concentrations above 19,000 mg/L) in groundwater west and north of FPL's property without creating adverse environmental impacts. A further objective of this Consent Agreement is to reduce the rate of, and, as an ultimate goal, arrest migration of hypersaline groundwater. Recognizing other factors beyond FPL's control may influence movement of groundwater in the surficial aquifer, FPL shall reasonably take into account such factors when developing and implementing remedial actions to minimize the timeframe for achieving compliance with this Consent Agreement.

a. Abatement.

i. DERM acknowledges that FPL is planning to undertake the following:

1. pursue permitting, construction and operation of up to six Upper Floridan Aquifer System wells in accordance with the Site Certification Modification that is the subject of DOAH Case No. 15-1559EPP.

2. continue the use of the existing marine wells (SW-1, SW-2, and PW-1) as a short term resource to lower and maintain salinities. FPL shall work to avoid the use of the marine wells, except under extraordinary circumstances.

3. continue operation of the authorized L-31E canal pumps as a short term resource only, in accordance with the terms and conditions of the applicable approvals. FPL acknowledges that the use of water from the L-31E canal is intended only as a short term resource to lower CCS salinity. FPL anticipates the need for this resource for the next two years to reduce salinity as it transitions into the long term resources that are intended to maintain the lower salinity in the CCS. FPL acknowledges that additional regulatory

approvals will be required for continuation of this activity beyond the expiration of the existing approvals.

ii. FPL shall evaluate alternative water sources to offset the CCS water deficit and reduce chloride concentration in the CCS, and as a means of abating the westward movement of CCS groundwater. FPL will consider the practicality and appropriateness of using reclaimed wastewater from the Miami-Dade County South District Waste Water Treatment Plant as an alternative water source. FPL will provide DERM a summary of its Alternative Water Supply plan within 180 days of executing the Consent Agreement. FPL recognizes the importance and potential for reuse water, and FPL will make good faith efforts to implement the use of reuse water where practicable.

iii. FPL shall also conduct a review of the Interceptor Ditch operations to determine if current design and/or operations can be practicably modified to improve its function recognizing the current status of the CCS and surrounding wetlands. FPL will provide a summary of its Interceptor Ditch Review within 180 days of executing the Consent Agreement.

iv. The alternative water sources and any modifications to Interceptor Ditch design or operation shall be authorized through the appropriate regulatory processes and shall be demonstrated to not create adverse impacts to surface waters, groundwater, wetland or other environmental resources consistent with the Fifth Supplemental Agreement.

b. <u>Remediation</u>. FPL shall develop and implement the following actions to intercept, capture, contain, and retract hypersaline groundwater (groundwater with a chloride concentration of greater than 19,000 mg/L) to the Property boundary to achieve the objectives of this Consent Agreement.

i. Phase I. FPL shall design, permit, and construct a Biscayne Aquifer Recovery Well System (RWS) based on the results of a variable density dependent groundwater model which shall be sufficient to support the design of the RWS to intercept, capture, and contain the hypersaline plume; support authorization through the appropriate regulatory processes; and demonstrate that it will not create adverse impacts to groundwater, wetland (hydroperiod or water-stage), or other environmental resources. Final operation and design will be informed by an Aquifer Performance Test (APT). FPL shall provide its design and supporting information for the Recovery Well System and associated monitoring wells for DERM review and approval within 180 days of executing the Consent Agreement. FPL shall proceed with implementation within one year of executing the Consent Agreement, subject to regulatory timelines not in FPL's control. The initial design will be based on up to 12 MGD disposal capacity recognizing existing on-site capability. Efficacy of this design constraint will be reviewed in Phases 2, 3, and 4.

ii. Phase 2. FPL shall operate the RWS in accordance with all local, state, and federal regulatory requirements, collect data as required by the monitoring program, and employ the data to inform and reduce the uncertainty of the groundwater model. Status and efficacy of the system operation in meeting the objectives of this Consent Agreement and results of continued groundwater model refinement will be provided in the annual reports required in Paragraph 17d.

iii. Phase 3. After five years, FPL shall evaluate the effectiveness of the RWS in achieving the goal to intercept, capture, contain, and ultimately retract the hypersaline groundwater plume. This evaluation shall include estimated milestones and be based on the results of the monitoring data and refined groundwater/surfacewater model, which will be submitted to DERM. If the analysis indicates that the RWS is not anticipated to achieve the goal to intercept, capture, contain, and ultimately retract the hypersaline groundwater plume, FPL shall make recommendations for modifications to the project components and/or designs to ensure the ability of the system to achieve the objectives of the Consent Agreement. The evaluation and any proposed revisions shall be submitted to DERM for review and approval.

iv. Phase 4. After ten years, FPL shall review the results of the activities and progress to achieve the objectives of this Consent Agreement, and this evaluation shall be submitted to DERM. If monitoring demonstrates that the activities are not achieving the objectives of this Consent Agreement, FPL shall revise the project components and/or designs to ensure the ability of the system to achieve the objectives of this

Consent Agreement. The proposed revisions shall be submitted to DERM for review and approval.

c. Regional Hydrologic Improvement Projects. In addition, FPL agrees to undertake the following:

i. Raise control elevations in the Everglades Mitigation Bank. Within 30 days of the effective date of this Consent Agreement, FPL shall raise the control elevations of the FPL Everglades Mitigation Bank ("EMB") culvert weirs to no lower than 0.2 feet lower than the 2.4 foot trigger of the S-20 structure and shall maintain this elevation. After the first year of operation, FPL shall evaluate the change in control elevation, in regards to improvements in salinity, water quality, and lift in the area, and if FPL determines that the change in control elevations is not effective, or that FPL is negatively impacted in receiving mitigation credits as a result of this action, FPL will consult with DERM and propose potential alternatives.

ii. Fill portions of the Model Lands North Canal within the Everglades Mitigation Bank. Within 30 days of the effective date of the Consent Agreement, FPL shall seek all necessary regulatory approvals to place excavated fill from the adjoining roadway into the Model Lands North Canal within FPL's Everglades Mitigation Bank. Upon issuance of such regulatory approvals, FPL shall, starting on the east end, fill the Model Lands North Canal. This Consent Agreement only requires FPL to fill to the extent the fill is available from the adjoining roadway permitted to be degraded.

iii. If the District determines that flowage easements are needed from FPL in order to increase the operational stages of the S-20 water control structure as planned and approved by CERP, FPL agrees to provide such flowage easements for FPL owned land within the Everglades Mitigation Bank, in favor of the District within six months of the determination.

iv. FPL acknowledges the benefit of hydrologic restoration projects contemplated by the Comprehensive Everglades Restoration Project ("CERP"), as well as other government entities, adjacent and to the west of the CCS in controlling movement of hypersaline and saline waters in the Biscayne Aquifer. FPL commits to working with local, state and federal agencies to facilitate implementation of these projects to promote improved hydrologic conditions.

d. Monitoring and Reporting. FPL shall conduct monitoring to evaluate the progress made in achieving the objectives of this Consent Agreement. This includes actions that result from satisfying the abatement, remediation and hydrologic improvement components of this Consent Agreement. FPL shall initiate the monitoring and reporting requirements identified below within 30 days of executing the Consent Agreement. The monitoring shall include the following:

   i. FPL shall facilitate DERM access to all data from continuous electronically monitored stations.

   ii. FPL shall continue to provide monthly and quarterly reports substantially consistent with those required in M-D Class I permit CLI-2014-0312, beyond the expiration of the permit.

   iii. FPL shall employ Continuous Surface Electromagnetic Mapping (CSEM) methods to assess the location and orientation of the hypersaline plume west and north of the CCS.

   iv. FPL shall add three groundwater monitoring clusters (shallow, mid and deep) to monitor groundwater conditions in the model lands basin. The well clusters shall be similar in design and function to existing groundwater monitoring wells in the region as part of the CCS monitoring program, and shall be geographically located in consultation with DERM.

   v. FPL shall submit annual reports providing an evaluation of progress in achieving the objectives of this Consent Agreement, status of implementing projects identified above, and the results of monitoring to determine the impacts of these activities. Recommendations for refinements to the activities will be included in the annual report. This may include deletions of monitoring that is demonstrated to no longer be needed, or additional monitoring that is warranted based on observations.

SAFETY PRECAUTIONS

18. FPL shall maintain the subject property during the pendency of this Consent Agreement in a manner which shall not pose a hazard or threat to the public at large or the environment and shall not cause a nuisance or sanitary nuisance as set forth in Chapter 24 of the Code of Miami-Dade County, Florida.

VIOLATION OF REQUIREMENTS

19. This Consent Agreement constitutes a lawful order of the DERM Director and is enforceable in a civil court of competent jurisdiction. Violation of any requirement of this Consent Agreement may result in enforcement action by DERM. Each violation of any of the terms and conditions of this Consent Agreement by FPL shall constitute a separate offense.

SETTLEMENT COSTS

20. FPL hereby certifies that it has the financial ability to comply with the terms and conditions herein and to comply with the payment of settlement costs specified in this Agreement.

21. DERM has determined that due to the administrative costs incurred by DERM for this matter, a settlement of $30,000.00 is appropriate. FPL shall, within sixty (60) days of the effective date of this Consent Agreement, submit to DERM a check in the amount of $30,000.00 for full settlement payment. The payment shall be made payable to Miami-Dade County and sent to the Division of Environmental Resources Management, c/o Barbara Brown, 701 NW 1st Court, 6th Floor, Miami, FL 33136-3912.

22. In the event that FPL fails to submit, modify, implement, obtain, provide, operate and/or complete those items listed in paragraph 17 herein, FPL shall pay DERM a civil penalty of one hundred dollars ($100.00) per day for each day of non-compliance and FPL may be subject to enforcement action in a court of competent jurisdiction for such failure pursuant to those provisions set forth in Chapter 24 of the Code of Miami-Dade County. Any such payments shall be made by FPL to DERM within ten days of receipt of written notification and shall be sent to the Division of Environmental Resources Management, 701 NW 1st Court, 6th Floor, Miami, FL 33136-3912.

GENERAL PROVISIONS

23. FPL shall allow any duly authorized representative of DERM, with reasonable notification, to enter and inspect the CCS, Floridan wells, extraction wells, or any other relevant facilities, at any reasonable time for the purpose of ascertaining the state of compliance with the terms and conditions of this Consent Agreement. DERM shall comply with the plant safety and security precautions. FPL shall provide and maintain a point of contact at the Turkey Point Power Plant to assist DERM in accessing the facilities to be inspected.

24. On a quarterly basis (January, April, July, and October), DERM may collect surface and/or groundwater samples at the discretion of DERM at various monitoring locations in accordance with monitoring referenced in Paragraph 17 above.

25. FPL and DERM agree to cooperate and use best efforts moving forward related to this Consent Agreement.

26. Disputes related to or arising out of this Consent Agreement shall be construed consistent with the laws of the State of Florida and the United States, as applicable, and shall be filed in the state or federal courts of the State of Florida, as appropriate. Proceedings shall take place exclusively in the Circuit Court for Miami-Dade County, Florida or the United States District Court for the Southern District of Florida.

27. In consideration of the complete and timely performance by FPL of the obligations contained in this Consent Agreement, DERM waives its rights to seek judicial imposition of damages or civil penalties for the matters alleged in Notice of Violation and Consent Agreement.

28. Where FPL cannot meet timetables or conditions due to circumstances beyond FPL's control, FPL shall provide written documentation to DERM which shall substantiate that the cause(s) for delay or non-compliance was not reasonably in FPL's control. DERM shall make a determination of the reasonableness of the delay for the purpose of continued enforcement pursuant to paragraph 22 of this Consent Agreement.

29. DERM expressly reserves the right to initiate appropriate legal action to prevent or prohibit future violations of applicable laws, regulations, and ordinances or the rules promulgated thereunder.

30. Entry of this Consent Agreement does not relieve FPL of the responsibility to comply with applicable federal, state or local laws, regulations, and ordinances.

31. FPL acknowledges that this Consent Agreement is within the jurisdiction of Miami-Dade County. Nothing in this Consent Agreement is intended to expand, nor shall this Consent Agreement be construed to expand, the regulatory authority or jurisdiction of Miami-Dade County.

32. This Consent Agreement shall neither be evidence of a prior violation of this Chapter nor shall it be deemed to impose any limitation upon any investigation or action by DERM in the enforcement of Chapter 24 of the Code of Miami-Dade County.

33. This Consent Agreement shall become effective upon the date of execution by the DERM Director, or the Director's designee.

October 6, 2015
Date

Eric E. Silagy
President & CEO
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408
Respondent

Before me, the undersigned authority, personally appeared Eric Silagy, who after being duly sworn, deposes and says that they have read and agreed to the foregoing.

Subscribe and sworn to before me this 6th day of October, 2015 by

Eric Silagy (name of affiant).

Personally known ✓ or Produced Identification ______.
(Check one)

Type of Identification Produced: ____________________________.

LISA GROVE
MY COMMISSION # FF 154741
EXPIRES: December 14, 2016
Bonded Thru Budget Notary Services

Lisa Grove

Notary Public Signature

Lisa Grove

Notary Public Printed Name

DO NOT WRITE BELOW THIS LINE – GOVERNMENT USE ONLY

OCT 7, 2015

Date

Lee N. Hefty, DERM Director

Miami-Dade County

Witness

Barbara Brown

Witness

Exhibit A
FPL Turkey Point Property Boundary
for Purposes of Consent Agreement (~9000 acres)

0 0.5 1 2 Miles

2015_FPL_TP_facility_bnd90K.mxd - October 6, 2015

BEFORE THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION	)	IN THE OFFICE OF THE SOUTHEAST DISTRICT
v.	)	OGC FILE NO. 16-0241
FLORIDA POWER & LIGHT COMPANY,	)	

CONSENT ORDER

This Consent Order ("Order") is entered into between the State of Florida Department of Environmental Protection ("Department") and Florida Power & Light Company ("Respondent" or "FPL") to reach settlement of certain matters at issue between the Department and Respondent.

The Department finds:

1. The Department is the administrative agency of the State of Florida having the power and duty to protect Florida's air and water resources and to administer and enforce the provisions of Chapter 403, Florida Statutes ("F.S."), and the rules promulgated and authorized in Title 62, Florida Administrative Code ("F.A.C."). The Department has jurisdiction over the matters addressed in this Order.

2. FPL is a "person" as defined under Section 403.031(5), F.S.

3. FPL owns and operates a cooling canal system ("CCS"), an approximately 5,900-acre network of unlined canals at Turkey Point Power Plant. FPL began construction of the CCS in 1972. Turkey Point originally obtained cooling water for the facility by drawing surface water from an intake channel connected to Biscayne Bay, and discharging that water, after it had been heated, into Biscayne Bay and Card Sound through a series of discharge canals. In 1971, FPL entered into a Final Judgment with the U.S. Department of Justice that required the permitting, construction, operation, and maintenance of a closed-loop cooling canal configuration with limitations on makeup and blowdown water.

4. FPL is the permittee and operates the CCS under National Pollutant Discharge Elimination System/Industrial Wastewater Permit Number FL0001562 (the "Permit"). This Permit is issued pursuant to the federal NPDES program and Florida industrial wastewater permitting program. The Permit authorizes wastewater discharges from the generating units through two internal outfalls into the CCS. The Permit does not authorize direct discharges to surface waters of the state. The Permit authorizes discharges from the CCS into Class G-III groundwater which is part of the surficial aquifer system. Condition IV.1 of the Permit provides that discharges to groundwater shall not cause a violation of the minimum criteria for ground water specified in Rules 62-520.400, F.A.C. and 62-520.430, F.A.C. Rule 62-520.400, F.A.C., provides that discharges to ground water shall not impair the reasonable and beneficial use of adjacent waters, either ground or surface.

5. Turkey Point Power Plant Units 3 through 5 are licensed under the Florida Power Plant Siting Act, Chapter 403, Part II, F.S. Those units operate in accordance with the conditions of certification in their license, PA 03-45. Condition of Certification X requires FPL to execute a 5th Supplemental Agreement with the South Florida Water Management District ("SFWMD") and to revise FPL's monitoring obligations, which resulted in the Turkey Point Plant Groundwater, Surface Water and Ecological Monitoring Plan, as amended, ("2009 Monitoring Plan") incorporated as Exhibit A to the Fifth Supplemental Agreement between the South Florida Water Management District and FPL entered on October 16, 2009.

6. Historical data show that, when the CCS was constructed in the 1970's, saline water had already intruded inland along the coast due to many factors such as freshwater withdrawals, drought, drainage and flood control structures, and other human activities. To date, the relative contributions of the different factors toward westward movement of the saltwater interface have not been fully identified.

7. FPL provided information on action they have already taken on several fronts to address the broader regional risks and the many causes of saltwater intrusion. In 2010, FPL installed a gated culvert approximately 3.8 miles inland of Biscayne Bay in the Card Sound Road Canal to eliminate an unrestricted inland conveyance of saltwater from the bay. Also, in 2014, FPL installed a broad, fix crested weir in the S-20 Discharge Canal to prevent the historic migration of bay saltwater up to the S-20 Canal.

8. The phrase "hypersaline water/plume" as used in this Order means water that exceeds 19,000 mg/L chlorides. The term "saltwater interface" ("SWI") as used in this Order means the intersection of class G-II and G-III groundwaters.

9. The CCS includes an approximately 18 foot deep interceptor ditch along the western edge of the CCS. As approved and constructed, the interceptor ditch system has been effective at restricting the westward movement of the saline water from the CCS in the upper portion of the aquifer but has not restricted the westward movement of saline waters into the deeper portions of the aquifer. Saline water from the CCS has moved, at depth, westward of the L-31E Canal in excess of those amounts that would have occurred without the existence of the CCS.

10. The Department issued an Administrative Order (OGC No. 14-0741) to FPL related to the CCS at Turkey Point on December 23, 2014 and made final by an Order of the Department issued on April 21, 2016. The Administrative Order requires FPL to reduce the salinity in the CCS. This Consent Order supersedes all of the requirements of that Administrative Order.

11. FPL conducted or implemented dredging, vegetation control, water stage management, and chemical additives to the CCS to maintain the thermal efficiency of the system and to control salinity and temperature.

12. Elevated salinity levels in the CCS cause, or at a minimum contribute to, the hypersaline discharges into the groundwater. Reducing the CCS surface water salinity from an elevated base salinity condition will require certain measures such as a greater

addition of relatively fresher water, removal of salt mass from the CCS, and management of CCS inflows and outflows. Ambient weather factors, such as precipitation amounts, temperatures, and regional water levels can also affect CCS salinity levels.

13. On October 7, 2015, FPL entered into a Consent Agreement with Miami-Dade County to resolve a Notice of Violation from the County dated October 2, 2015. Pursuant to paragraph 17 of the Consent Agreement, the objective is for FPL to demonstrate a statistically valid reduction in the salt mass and volumetric extent of the hypersaline water (as represented by chloride concentrations above 19,000 mg/L) in groundwater west and north of FPL's property without creating adverse environmental impacts. A further objective of the Consent Agreement is to reduce the rate of and, as an ultimate goal, arrest migration of hypersaline groundwater.

14. On April 25, 2016, the Department issued a Notice of Violation (OGC File No.: 16-0241) ("NOV") to FPL stating that the CCS is the major contributing cause to the continuing westward movement of the saline water interface, and that the discharge of hypersaline water contributes to saltwater intrusion. In the NOV, the Department found that saltwater intrusion into the area west of the CCS is impairing the reasonable and beneficial use of adjacent G-II groundwater in that area. FPL has operated the CCS under regulatory approvals, and the Department has not previously issued FPL either a Warning Letter or a Notice of Violation concerning FPL's operation of the CCS.

15. On April 25, 2016, the Department issued a Warning Letter, #WL 16-000151W13SED, to FPL concerning sampling events that indicated that ground water

originating from beneath the CCS is reaching tidal surface waters connected to Biscayne Bay in artificial deep channels immediately adjacent to the CCS. The Warning Letter requested that FPL provide facts to assist in determining whether any violations of Florida law have occurred.

16. The NOV directed FPL to enter into consultations to develop a consent order to, at a minimum, remediate the CCS contribution to the hypersaline plume, reduce the size of the hypersaline plume, and prevent future harm to waters of the State. FPL entered into consultations with the Department as required by the Orders for Corrective action in the NOV. The consultations resulted in resolutions to address the violations alleged in the NOV and issues raised in the Warning Letter, as memorialized in this Order.

17. On May 16, 2016, FPL submitted to the Department the nutrient monitoring results from certain surface water monitoring stations in deep channels adjacent to the CCS for total nitrogen, total phosphorous, TKN, and chlorophyll a. The Department reviewed the information by FPL and determined that no exceedances of surface water quality standards were detected in Biscayne Bay monitoring. This Order is intended to minimize the potential for future exceedances.

18. This Order and FPL's compliance with the requirements set forth in this Order address issues identified in the Department's Warning Letter, Administrative Order and NOV.

Respondent and the Department mutually agree and it is

ORDERED:

19. The first objective of this Order is for FPL to cease discharges from the CCS that impair the reasonable and beneficial use of the adjacent G-II ground waters to the west of the CCS in violation of Condition IV.1 of the Permit and Rule 62-520.400, F.A.C. FPL shall accomplish this first objective by undertaking freshening activities as authorized in the Turkey Point site certification, by eliminating the CCS contribution to the hypersaline plume, by maintaining the average annual salinity of the CCS at or below 34 Practical Salinity Units ("PSU"), by halting the westward migration of hypersaline water from the CCS, and by reducing the westward extent of the hypersaline plume to the L-31E within 10 years, thereby removing its influence on the saltwater interface, without creating adverse environmental impacts. The second objective of this Order is for FPL to prevent releases of groundwater from the CCS to surface waters connected to Biscayne Bay that result in exceedances of surface water quality standards in Biscayne Bay. FPL shall accomplish this second objective primarily by undertaking restoration projects in the Turtle Point Canal and Barge Basin area. The third objective of this Order is for FPL to provide mitigation for impacts related to the historic operation of the CCS, including but not limited to the hypersaline plume and its influence on the saltwater interface.

20. To achieve the first objective of this Order, FPL shall:

a. Achieve a CCS average annual salinity of at or below 34 PSU ("threshold") at the completion of the fourth year of freshening activities, which are authorized by the Turkey Point site certification modification. If FPL fails to reach an annual average salinity of at or below 34 PSU by the end of the fourth year of freshening activities, within 30 days of failing to reach the required threshold, FPL shall submit a plan to the Department detailing additional measures, and a timeframe, that FPL will implement to achieve the threshold. Subsequent to attaining the threshold in the manner set forth above, if FPL fails more than once in a 3 year period to maintain an average annual salinity of at or below 34 PSU, FPL shall submit, within 60 days of reporting the average annual salinity, a plan containing additional measures that FPL shall implement to achieve the threshold salinity level.

b. Submit a thermal efficiency plan within 180 days of the effective date of the Order that shall include a detailed description for the CCS to achieve a minimum of 70 percent thermal efficiency. This efficiency plan shall address water stage management, vegetation control, dredging, chemical additives to the CCS for facility operation, and upset recovery. FPL shall implement the efficiency plan within 90 days of being instructed to do so by the Department.

c. Implement a remediation project that shall include a recovery well system that will halt the westward migration of hypersaline water from the CCS within 3 years and reduce the westward extent of the hypersaline plume to the L-31E canal within 10 years without adverse environmental impacts.

i. Within 30 days of the effective date of this Order, provide the Department with available detailed plans for this remediation project, including supporting data, that are designed to halt the westward migration of the hypersaline plume within 3 years of commencement of the remediation project and retract the hypersaline plume to the L-31E canal within 10 years of the commencement of the remediation project. Location, volume and movement of the hypersaline plume shall be determined by Continuous Surface Electromagnetic Mapping ("CSEM") technology as detailed below.

ii. Apply for appropriate regulatory approvals within 90 days of the effective date of this Order and begin construction of this remediation project within 30 days after receipt of all necessary regulatory approvals. FPL shall advise the Department of any modifications to the submitted plans that result from regulatory reviews. FPL shall commence the operation of this remediation project upon completion of construction. FPL shall provide the Department with written notice of the date FPL commenced operation of this remediation project.

iii. For determining compliance, the westward migration of the hypersaline plume shall be deemed halted if the third CSEM survey shows no net increase in hypersaline water volume and no net westward movement in the leading edge of the hypersaline plume.

iv. To ensure overall remediation objectives are attained in a timely manner, if the second CSEM survey indicates that the net westward migration of the hypersaline plume is not being halted, then, within 180 days of the second CSEM survey, FPL shall develop and submit for approval to the Department a plan with specific actions to achieve the objectives of the remediation project. If the third CSEM survey still indicates the net westward migration of the hypersaline plume has not halted, FPL shall implement the approved additional measures within 30 days after submittal of the third CSEM report to the Department.

v. At the conclusion of the fifth year of operation of the remediation project, FPL shall evaluate and report to the Department, within 60 days, the effectiveness of the system in retracting the hypersaline plume to the L-31E canal within 10 years. If this report shows the remediation project will not retract the hypersaline plume to the L-31E canal within 10 years due to adverse environmental impacts of remedial measures or other technical issues, FPL shall provide an alternate plan for Department review and approval. FPL shall begin implementing the alternate plan within 30 days of receipt of notice that the alternate plan has been approved.

21. To achieve the second objective of this Order, FPL shall:

a. Complete Barge Basin and Turtle Point Canal restoration projects within 2 years of receiving the final regulatory approval. Within 60 days of the effective date of this Order, FPL shall provide the Department with a detailed plan and design of the restoration projects to prevent releases of groundwater from the CCS to surface waters connected to Biscayne Bay that result in exceedances of surface water quality standards in Biscayne Bay. Not more than 90 days after the effective date of this Order, FPL shall prepare and submit permit applications to relevant regulatory agencies (including the Department, the United States Army Corp of Engineers, and Miami-Dade County, as necessary) to address the restoration of the Turtle Point Canal and Barge Basin. Project success shall be based on full project completion and monitoring results of surface water sampling sites TPBBSW-4, TPBBSW-10, and TPBBSW-7T.

b. Within 90 days of the effective date of this Order, submit a detailed report outlining the potential sources of the nutrients found in the CCS, including chemical products used for plant operations. The report shall include a plan for minimizing nutrient levels in the CCS, which shall be implemented within 90 days after being instructed to do so by the Department.

c. Within 120 days of the effective date of this Order, conduct a thorough inspection of the CCS periphery including all dams, dikes, berms, and appurtenant structures using sound engineering judgment and best practices. FPL shall submit a detailed report to the Department of the inspection results, including underlying data. The inspection must be conducted by an independent qualified Florida licensed professional engineer. The term qualified means having successfully completed the Mine Safety and Health Administration Qualification for Impoundment Inspection course in addition to the Annual Retraining for Impoundment Qualification, or equivalent qualifications. The engineer shall also review available documentation and include in the report any actions necessary to ensure the integrity of the CCS. If the inspection identifies a material breach or structural defect in a peripheral levee of the CCS, FPL shall, within

60 days, submit a detailed description of the plan to address any material breaches or structural defects. FPL shall implement the plans to address any material breaches or structural defects within 60 days of the report mandated under this paragraph.

22. If FPL seeks renewal of the Combined License for either Unit 3 or 4 from the Nuclear Regulatory Commission, FPL shall provide the Department any information provided to the NRC detailing the future operating viability, including environmental and natural resource impacts, of the CCS and any potential alternative cooling technologies during the second renewal period.

23. To achieve the third objective of this Order, FPL shall undertake the following:

a. Complete an analysis, within 2 years from the effective date of this Order, with input from the Department and other agencies as selected by the Department, using the variable density three dimensional groundwater model developed under the Miami-Dade County Consent Agreement, that seeks to allocate relative contributions of other entities or factors to the movement of the SWI.

b. Enter into an agreement within 1 year with SFWMD, if SFWMD requests, to convey to SFWMD, FPL property interests in essential properties within the Biscayne Bay Coastal Wetlands Phase I project to facilitate the Comprehensive Everglades Restoration Plan in exchange for payment based on a jointly approved appraisal process or other mutually agreeable considerations. (See Attachment A).

c. Deposit $1.5 million into a Florida Department of Financial Services escrow account in accordance with an escrow agreement signed by FPL, the Department and the Florida Department of Financial Services. The escrow account shall be used to finance projects in the Turkey Point region that support mitigation of saltwater intrusion.

d. Conduct grab sampling within 90 days of the effective date of this Order, to improve trend analysis in Biscayne Bay and Card Sound surface waters, every two months, taking both top and bottom samples, for two years from the effective date of this Order at six sites as shown in Attachment B. The parameters sampled shall be: temperature, conductivity, pH, dissolved oxygen, turbidity, salinity, tritium, ammonia, nitrate + nitrite, total Kjedahl nitrogen, orthophosphate, total phosphorus, chlorophyll-*a*, total depth, and Secchi disk depth.

MONITORING REQUIREMENTS

24. Quality assurance and quality control for all monitoring requirements under this Order shall be achieved by compliance with the Quality Assurance Project Plan under the 2009 Monitoring Plan.

25. FPL shall timely apply for all regulatory approvals necessary for compliance with the monitoring requirements in this Order.

26. FPL shall continue to implement the monitoring program for the CCS, the 2009 Monitoring Plan, until such time as a monitoring plan is enacted pursuant to Section 403.087, F.S.

27. In addition to the monitoring requirements contained in the 2009 Monitoring Plan, FPL shall, within 90 days of the effective date of this Order, request or apply for regulatory approval to:

a. Obtain monitoring data from the USGS for the following wells for inclusion in the monitoring database: G-3946-S, G-3946-D, G-3900, G-3976, G-3966, and G-3699.

b. Install and monitor, consistent with the parameters and frequency set forth in the 2009 Monitoring Plan, a new 3 well cluster at G-3164. Construction shall commence within 180 days of FPL's receipt of all necessary regulatory approvals for the installation of the wells.

c. Replace and monitor, consistent with the parameters and frequency set forth in the 2009 Monitoring Plan well TPGW-8S. Construction shall commence within 180 days of FPL's receipt of all regulatory approvals necessary for compliance with this requirement.

d. Install and monitor, consistent with the parameters and frequency set forth in the 2009 Monitoring Plan a new deep well (to be designated as TPGW-20) located at the City of Homestead baseball complex, east of Kingman Road (SW 152nd Ave.) near the western parking area. Construction shall commence within 180 days of FPL's receipt of all regulatory approvals necessary for compliance with this requirement. The deep well will have a screened interval open to the deep high flow interval identified in the same manner as those described in the 2009 Monitoring Plan.

28. FPL shall expand the 2009 Monitoring Plan database to include all additional water monitoring data related to this Order required by all other governmental agencies and entities, including but not limited to the SFWMD, Nuclear Regulatory Commission, Miami-Dade County and the Florida Department of Health, as well as all monitoring data that is required in this Order.

29. In addition to the other monitoring requirements in this Order and for purposes of monitoring progress toward achievement of the hypersaline plume retraction, including determining whether the westward migration of the hypersaline plume has been halted and determining the rate of decline of saline levels in the CCS surface waters over time, the following monitoring requirements shall be met:

a. FPL shall conduct and report to the Department a baseline CSEM survey of the hypersaline plume after freshening activities are in operation but before the complete recovery well system begins operation. This will be the "Baseline Survey."

b. FPL shall conduct a CSEM survey within 30 days after the first year of recovery well operations and report the results to the Department.

c. FPL shall conduct a CSEM survey within 30 days after the second year of recovery well operations and report the results to the Department. This survey shall be the second CSEM survey.

d. FPL shall conduct a CSEM survey within 30 days after the third year of recovery well operations and report the results to the Department. This survey shall be the third CSEM survey.

e. FPL shall conduct and report to the Department subsequent CSEM surveys of the hypersaline plume 2 years after the third CSEM survey and every 2 years thereafter.

f. FPL shall monitor average weekly mass removal of salt as represented by total dissolved solids ("TDS"), by monitoring flow rate and weekly average TDS of the full extraction system, beginning at the time of commencement of the hypersaline plume remediation project operation.

g. FPL shall monitor average weekly chloride concentration of extracted water for the full extraction system, beginning at the time of commencement of the hypersaline plume remediation project operation.

h. FPL shall monitor average daily volume of hypersaline water extraction for the full extraction system, from beginning at the time of commencement of the Plume Extraction operation.

i. FPL shall maintain records of the operation of each extraction well (pump operation parameters such as: pump status, RPM, flow rate; water quality parameters such as salinity and TDS) and make such records available for review by the Department upon request, with reasonable notice.

j. FPL shall, when monitoring the salinity levels in the CCS, utilize all available monitoring resources in the CCS to obtain the average annual salinity rate. Specific monitoring points may not be excluded from the calculation unless such exclusion is allowed by the Department based upon a scientific reason. For the purposes of determining average annual salinities for the CCS, FPL shall use qualified hourly data (pursuant to the approved 2009 Monitoring Plan QAPP) from each of the CCS monitoring sites TPSWCCS-1, 2, 3, 4, 5, 6, and 7 collected beginning at 00:00 through 23:59 each day. The qualified hourly data for the day will be summed and divided by the number of qualified hourly values for the station that day. Stations with fewer than 12 qualified hourly data values in a given day shall not be used in the calculation of the CCS daily average. The daily averages for all qualified stations (up to seven per day) for a given day will be summed and divided by the number of qualified stations for that day to produce a qualified CCS daily average salinity value. The average annual salinity is calculated by summing the qualified CCS daily average salinity values from June 1st through May 31st and dividing the value by the number of days in the year.

k. FPL shall monitor TPBBSW7T consistent with the parameters and frequency in the 2009 Monitoring Plan.

30. FPL will take reasonable actions to select appropriate laboratories with sufficient capacity to avoid delay in receiving results due to backlogs. If such delay occurs, FPL will make reasonable efforts to resolve those delays.

REPORTING REQUIREMENTS

31. The Annual Monitoring Report required by the 2009 Monitoring Plan shall be expanded to include:

a. All additional water monitoring data required under this Order.

b. All additional water monitoring data related to this Order required by all other governmental agencies or entities, including but not limited to the SFWMD, Nuclear Regulatory Commission, Miami-Dade County, and the Florida Department of Health, as well as all monitoring data that is required in this Order.

c. A reporting of the average annual salinity of the CCS waters.

32. FPL shall provide a report to the Department at the conclusion of the year-long control elevation project described in paragraph 17 of the Miami-Dade Consent Agreement detailing the results of the year-long raise in control elevations in the Everglades Mitigation Bank.

33. FPL shall provide the Department a copy of all reports/summaries/reviews required under any other agreements with any other agency, such as the reports/ summaries/ reviews required by the Miami-Dade Consent Agreement.

NOTICES

34. FPL shall allow all authorized representatives of the Department access to the Facility at reasonable times for the purpose of determining compliance with the terms of this Order and the rules and statutes administered by the Department.

35. This Order supersedes all the requirements of the Administrative Order related to the CCS at Turkey Point. Upon execution of this Order, the DEP Administrative Order (OGC No. 14-0741) is hereby rescinded.

36. If any event, including administrative or judicial challenges by third parties unaffiliated with FPL, occurs which causes delay or the reasonable likelihood of delay in complying with the requirements of this Order, FPL shall have the burden of proving the delay was or will be caused by circumstances beyond the reasonable control of FPL and could not have been or cannot be overcome by FPL's due diligence. Neither economic circumstances nor the failure of a contractor, subcontractor, materialman, or other agent (collectively referred to as "contractor") to whom responsibility for performance is delegated to meet contractually imposed deadlines shall be considered circumstances beyond the control of FPL (unless the cause of the contractor's late performance was also beyond the contractor's control). Failure of regulatory agencies to issue required permits consistent with this Order shall be considered a circumstance beyond the control of FPL if FPL acted with due diligence in the permit application process. Upon occurrence of an event causing delay, or upon becoming aware of a potential for delay, FPL shall notify the Department within 2 working days and shall, within seven calendar days notify the Department in writing of (a) the anticipated length and cause of the delay, (b) the measures taken or to be taken to prevent or minimize the delay, and (c) the timetable by which FPL intends to implement these measures. If the parties can agree that the delay or anticipated delay has been or will be caused by circumstances beyond the reasonable control of FPL, the time for performance hereunder shall be extended. The agreement to extend compliance must identify the provision or provisions extended, the new compliance date or dates, and the additional measures FPL must take to avoid or

minimize the delay, if any. Failure of FPL to comply with the notice requirements of this paragraph in a timely manner constitutes a waiver of FPL's right to request an extension of time for compliance for those circumstances.

37. The Department, for and in consideration of the complete and timely performance by FPL of all the obligations agreed to in this Order, hereby conditionally waives its right to seek judicial imposition of damages, civil penalties, or injunctive relief for the violations described in the Notice of Violation and above up to the date of the filing of this Order. This waiver is conditioned upon FPL's complete compliance with all of the terms of this Order.

38. This Order is a settlement of the Department's civil and administrative authority arising under Florida law to resolve the matters addressed herein. This Order is not a settlement of any criminal liabilities which may arise under Florida law, nor is it a settlement of any violation which may be prosecuted criminally or civilly under federal law. Entry of this Order does not relieve FPL of the need to comply with applicable federal, state, or local laws, rules, or ordinances.

39. The Department hereby expressly reserves the right to initiate appropriate legal action to address any violations of statutes or rules administered by the Department that are not specifically resolved by this Order.

40. FPL is fully aware that a violation of the terms of this Order may subject FPL to judicial imposition of damages, civil penalties up to $10,000.00 per day per violation, and criminal penalties.

41. FPL acknowledges and waives its right to an administrative hearing pursuant to sections 120.569 and 120.57, F.S., on the terms of this Order. FPL also acknowledges and waives its right to appeal the terms of this Order pursuant to section 120.68, F.S.

42. Electronic signatures or other versions of the parties' signatures, such as .pdf or facsimile, shall be valid and have the same force and effect as originals. No modifications of the terms of this Order will be effective until reduced to writing, executed by both FPL and the Department, and filed with the clerk of the Department.

43. The terms and conditions set forth in this Order may be enforced in a court of competent jurisdiction pursuant to sections 120.69 and 403.121, F.S. Failure to comply with the terms of this Order constitutes a violation of section 403.161(l)(b), F.S.

44. This Order is a final order of the Department pursuant to section 120.52(7), F.S., and it is final and effective on the date filed with the Clerk of the Department unless a Petition for Administrative Hearing is filed in accordance with Chapter 120, F.S.

45. When FPL demonstrates to the Department that it has fulfilled the requirements of this Order, the Department shall notify FPL in writing that all requirements of this Order are terminated except for the requirement to maintain the average annual salinity of the CCS at or below 34 PSU until an average annual salinity of the CCS is designated in a Department permit issued subsequent to the effective date of this Order.

46. Upon the timely filing of a petition, this Order will not be effective until further order of the Department.

47. FPL shall publish the following notice in a newspaper of daily circulation in Miami-Dade County, Florida. The notice shall be published one time only within 30 days of the effective date of the Order. FPL shall provide a certified copy of the published notice to the Department within 10 days of publication.

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF CONSENT ORDER

The Department of Environmental Protection ("Department") gives notice of agency action of entering into a Consent Order with FPL pursuant to section 120.57(4), F.S. The Consent Order addresses the westward migration of hypersaline water from the Turkey Point Facility and potential releases to deep channels on the eastern and southern side of the Facility. The Consent Order is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at the Department of Environmental Protection Office of General Counsel, 3900 Commonwealth Boulevard, Tallahassee, Florida 32399-3000.

Persons who are not parties to this Consent Order, but whose substantial interests are affected by it, have a right to petition for an administrative hearing under sections 120.569 and 120.57, F.S. Because the administrative hearing process is designed to formulate final agency action, the filing of a petition concerning this Consent Order means that the Department's final action may be different from the position it has taken in the Consent Order.

The petition for administrative hearing must contain all of the following information:

a) The OGC Number assigned to this Consent Order;

b) The name, address, and telephone number of each petitioner; the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding;

c) An explanation of how the petitioner's substantial interests will be affected by the Consent Order;

d) A statement of when and how the petitioner received notice of the Consent Order;

e) Either a statement of all material facts disputed by the petitioner or a statement that the petitioner does not dispute any material facts;

f) A statement of the specific facts the petitioner contends warrant reversal or modification of the Consent Order;

g) A statement of the rules or statutes the petitioner contends require reversal or modification of the Consent Order; and

h) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the Department to take with respect to the Consent Order.

The petition must be filed (received) at the Department's Office of General Counsel, 3900 Commonwealth Boulevard, MS# 35, Tallahassee, Florida 32399-3000 within 21 days of receipt of this notice. A copy of the petition must also be mailed at the time of filing Division of Water Resource Management, Industrial Wastewater Program at 2600 Blair Stone Road, Mail Station 3545, Tallahassee, Florida 32399-2400. Failure to file a petition within the 21-day period constitutes a person's waiver of the right to request an administrative hearing and to participate as a party to this proceeding under sections 120.569 and 120.57, F.S. Before the deadline for filing a petition, a person whose substantial interests are affected by this Consent Order may choose to pursue mediation as an alternative remedy under section 120.573, F.S. Choosing mediation will not adversely affect such person's right to request an administrative hearing if mediation does not result in a settlement. Additional information about mediation is provided in section 120.573, F.S. and Rule 62- 110.106(12), Florida Administrative Code.

FOR THE RESPONDENT:

Randall R. LaBauve
Vice-President, Environmental Services
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408

DONE AND ORDERED this 20th day of June, 2016, in Tallahassee, Florda.

STATE OF FLORIDA DEPARTMENT OF
ENVIRONMENTAL PROTECTION

John A. Coates

John A. Coates, P.E.
Director, Division of Water Resource Management

Filed, on this date, pursuant to section 120.52, F.S., with the designated Department Clerk, receipt of which is hereby acknowledged.

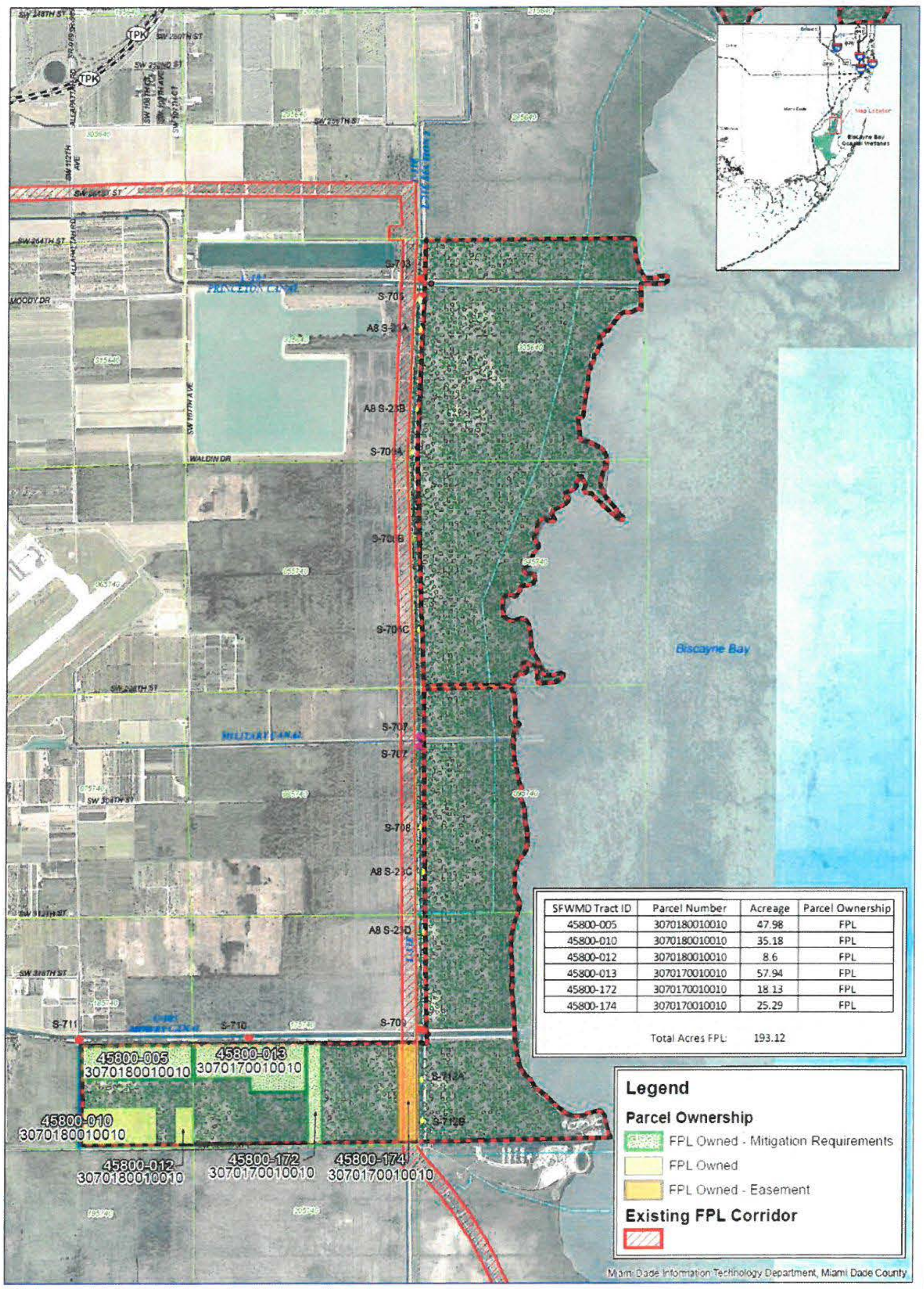
Clerk

Date 6/20/2016

Copies furnished to:

Lea Crandall, Agency Clerk
Mail Station 35

Attachment A



SFWMD Tract ID	Parcel Number	Acreage	Parcel Ownership
45800-005	3070180010010	47.98	FPL
45800-010	3070180010010	35.18	FPL
45800-012	3070180010010	8.6	FPL
45800-013	3070170010010	57.94	FPL
45800-172	3070170010010	18.13	FPL
45800-174	3070170010010	25.29	FPL

Total Acres FPL: 193.12

BBCW - Phase 1
L-31 East Flow-way
FPL Parcel Ownership - within Project

South Florida Water Management District
3301 Gun Club Rd, West Palm Beach, FL 33406
561-686-8800 - FL WATS 1-800-432-2045
P.O. Box 24680 - West Palm Beach, FL 33416-4680

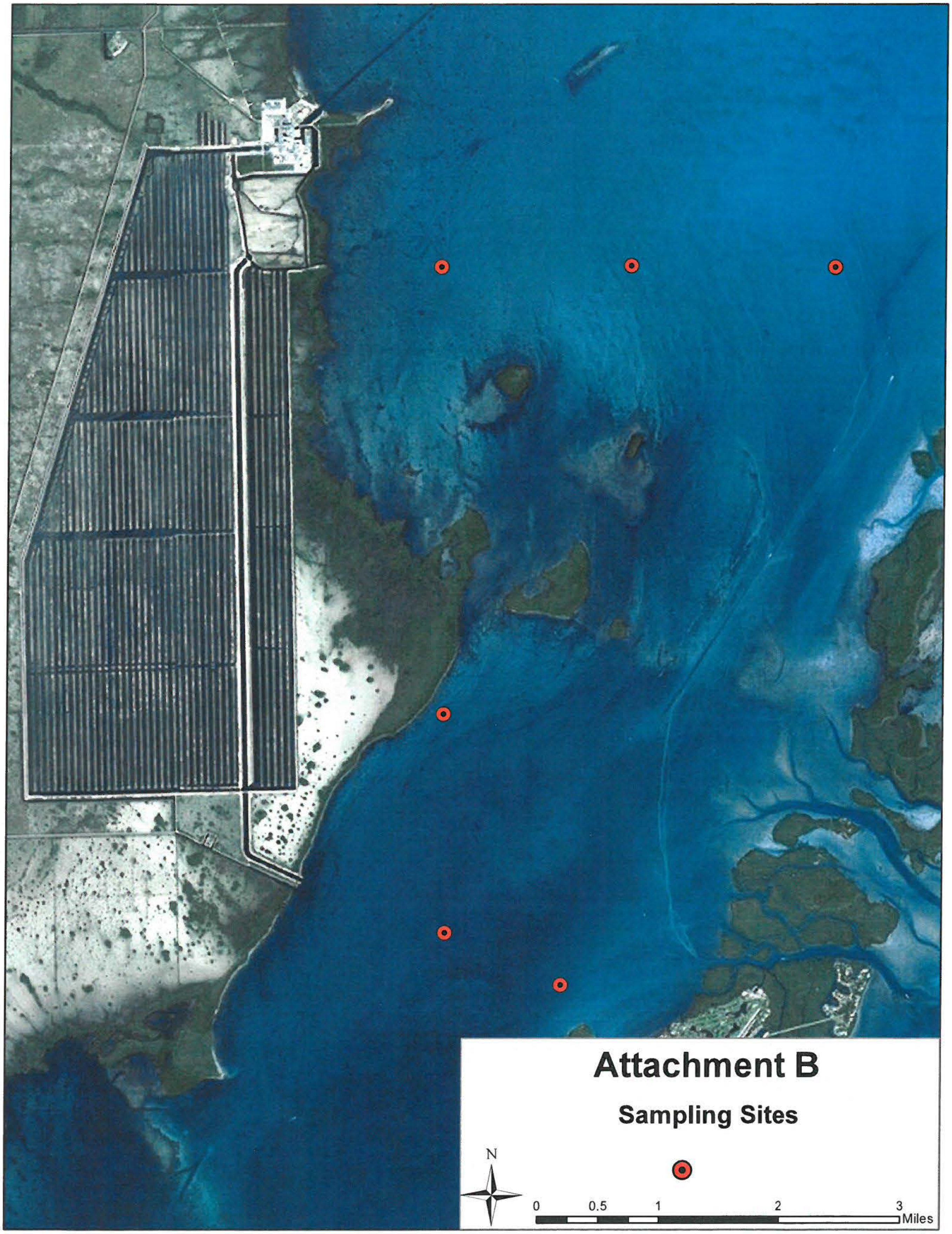
0 0.5 1 Miles

IMPORTANT DISCLAIMER
This map is a conceptual or planning tool only. The South Florida Water Management District does not guarantee or make any representation regarding the information contained herein. It is not self-executing or binding, and does not affect the interests of any persons or properties, including any present or future right or use of real property.

Map Date: June 2016

IT GEOSPATIAL SERVICES

User Name: hkoaturu Remedy Ticket: 00013376 Date Saved: 6/10/2016 1:42:22 PM \\ad.sfwmd.gov\dfsroot\sa_gis\arc_data\maps\proj\bbcw\am\BBCW PH1 L-31E_FPLwithinProject_Mitigation.mxd


Attachment B
Sampling Sites
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3
Miles

MIAMI-DADE COUNTY
Carlos A. Gimenez, Mayor

Department of Regulatory and Economic Resources
Environmental Resources Management
701 NW 1st Court, 6th Floor
Miami, Florida 33136-3912
T 305-372-6902 F 305-372-6630
miamidade.gov

August 15, 2016

Randall R. LaBauve, Vice President
Environmental Services
NextEra Energy, Inc.
700 Universe Blvd.
Juno Beach, Florida 33408

Certified Mail No. 7009 0080 0000 1050 8141
Return Receipt Requested

Re: Consent Agreement Addendum for the FPL Turkey Point power plant facility located at, near or in the vicinity of 9700 SW 344 Street, Unincorporated, Miami-Dade County, Florida.

Dear Mr. LaBauve:

Enclosed you will find an original of the above-referenced Consent Agreement Addendum which was executed today, August 15, 2016. Be advised that the date of execution initiates specific time periods with which FPL must comply as described in the Addendum.

If you have any questions concerning the above, please contact me at 305-372-6514 or email brownb@miamidade.gov. Thank you for your assistance in this matter.

Sincerely,

Barbara Brown

Barbara Brown
Special Projects Administrator
Regulatory Services

Enclosure

ec: Abbie Schwaderer-Raurell – CAO

Delivering Excellence Every Day

**ADDENDUM 1 TO THE OCTOBER 7, 2015 CONSENT AGREEMENT
BETWEEN
MIAMI-DADE COUNTY DEPARTMENT OF REGULATORY AND ECONOMIC RESOURCES, DIVISION OF ENVIRONMENTAL RESOURCES MANAGEMENT
AND
FLORIDA POWER & LIGHT COMPANY**

This Consent Agreement Addendum 1, entered into by and between Miami-Dade County Department of Regulatory and Economic Resources, Division of Environmental Resources Management (hereinafter referred to as "DERM"), and Florida Power & Light Company, (hereinafter referred to as "Respondent"), pursuant to Section 24-7(15)(c) of Chapter 24 of the Code of Miami-Dade County, shall serve to amend the October 7, 2015 Consent Agreement (Attachment 1) executed for the Turkey Point power plant facility and Cooling Canal System (CCS) located at, near or in the vicinity of 9700 SW 344 Street, Unincorporated, Miami-Dade County, Florida (DERM IW-3, IW-16, IW5-6229, DWO-10, CLI-2014-0312, HWR-851).

Subsequent to the Consent Agreement executed on October 7, 2015, a review of sampling data submitted by FPL and water quality sampling conducted by DERM revealed levels of ammonia as N exceeding the water quality standards set forth in Section 24-42(4) and clean-up target levels in Section 24-44(2)(f)(v)1, which constitutes water pollution as defined in Section 24-5 of the Code of Miami-Dade County. These results include ammonia as N in samples collected from surface water monitoring stations tidally connected to Biscayne Bay including, but not limited to, TPBBSW-7 and TPBBSW-8. This Consent Agreement requires FPL to take action to address the County's alleged violations of water quality standards and cleanup target levels relating to the exceedance of ammonia.

DERM and the Respondent agree to add Paragraph 34 to the October 7, 2015 Consent Agreement to address the referenced ammonia violations as follows:

34. Addendum 1.

    a. Within thirty (30) days of the execution of Addendum 1 of this Consent Agreement, the Respondent shall submit a Site Assessment Plan to DERM for review and approval which shall allow for the identification of the source(s) of the ammonia exceedances and the delineation of the vertical and horizontal extent of the subject ammonia exceedances in surface water. Said plan shall be adequate to address the ammonia exceedances to the surface waters surrounding the facility, including but not limited to, waters tidally connected to Biscayne Bay.

    b. Within sixty (60) days of DERM's approval of the Site Assessment Plan, the Respondent shall implement said plan and submit to DERM a Site Assessment Report for review and approval or approval with modifications which shall address the requirements of Item (a) above. The SAR shall include copies of the laboratory analytical reports, sampling logs, chain of custody forms and other information in accordance with the DERM approved Site Assessment Plan. All data submitted shall be in final form and no estimates or preliminary data will be accepted. All appropriate QA/QC documentation shall be submitted with the analytical results. In addition, all testing results submitted to DERM in response to this Addendum may be listed using the data form attached (Attachment 2).

c. Within ninety (90) days of approval of the Site Assessment Report, the Respondent shall submit to DERM for review and approval a Corrective Action Plan (CAP) prepared by a State of Florida registered professional engineer which, shall include, but not be limited to, the following:

   i. Design of an environmental restoration plan to correct the exceedences of ammonia standards and criteria,

   ii. Details of proposed process modifications or changes in operational systems to manage and control the source(s) of ammonia to prevent future violations of the provisions of Chapter 24 at the subject facility,

   iii. Physical, structural, or hydraulic modifications in the area of the CCS and adjacent surface waters to eliminate the contributions of CCS waters to the surface waters of Miami-Dade County, and

   iv. A time table for implementation and completion of the Corrective Action Plan.

d. Upon approval of the CAP, the Respondent shall implement said CAP in accordance with the approved timetable in order to cease discharges from the Turkey Point facility that cause or contribute to ammonia exceedances in violation of County water quality standards, cleanup target levels or which cause water pollution.

e. Within thirty (30) days of the execution of Addendum 1 to this Consent Agreement, the Respondent shall pay DERM administrative costs in the amount of five thousand dollars ($5,000.00). The payment shall be made payable to Miami-Dade County and sent to DERM, 701 NW 1st Court, 6th Floor, Miami, Florida 33136, Attention: Barbara Brown.

All other provisions of the October 7, 2015 Consent Agreement shall remain unchanged and in full force and effect for the duration of that Agreement.

This Consent Agreement Addendum 1 and the provisions herein shall become effective upon execution by the Director of DERM or the Director's designee.

[REMAINDER OF PAGE INTENTIONALLY BLANK; SIGNATURES APPEAR ON FOLLOWING PAGE]

8/12/2016
Date

Signature

Randall R. LaBauve
Print Name and Title

Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408
Respondent

NOTARY PUBLIC STATE OF FLORIDA
Notary Public State of Florida
Fannie Strickland
My Commission FF 992597
Expires 05/15/2020

Before me, the undersigned authority, personally appeared Randy R. LaBauve

who after being duly sworn, deposes and says that he has read the foregoing.

Subscribed and sworn to before me this 12th day of August, 20 16 by

Randy R. LaBauve.
(Name of affiant)

Personally Known ✓ or Produced Identification ____.
(Check One)

Type of Identification Produced: ____________________

Notary Public

DO NOT WRITE BELOW THIS LINE OFFICE USE ONLY

8-15-2016
Date

Lee N. Hefty, Director
Environmental Resources Management

Barbara Brown
Witness

Witness

MIAMI-DADE COUNTY, through its
DEPARTMENT OF REGULATORY AND
ECONOMIC RESOURCES, DIVISION OF
ENVIRONMENTAL RESOURCES
MANAGEMENT,

Complainant,

v.

FLORIDA POWER & LIGHT COMPANY,

Respondent.
_____________________________________/

CONSENT AGREEMENT

This Consent Agreement, entered into by and between the Complainant, MIAMI-DADE COUNTY, through its DEPARTMENT OF REGULATORY AND ECONOMIC RESOURCES, DIVISION OF ENVIRONMENTAL RESOURCES MANAGEMENT ("DERM"), and the Respondent FLORIDA POWER & LIGHT COMPANY ("FPL"), pursuant to Section 24-7(15)(c) of the Code of Miami-Dade County, shall serve to redress alleged violations of Chapter 24 of the Code of Miami-Dade County located near, surrounding, or in the vicinity of the Cooling Canal System located at Turkey Point on FPL's property, as further described herein, in Miami-Dade County, Florida.

DERM and FPL enter into the following Consent Agreement:

FINDINGS OF FACT

1. DERM is a division of Miami-Dade County, a political subdivision of the State of Florida, which is empowered to control and prohibit pollution and protect the environment within Miami-Dade County pursuant to Article VIII, Section 6 of the Florida Constitution, the Miami-Dade County Home Rule Charter and Section 403.182 of the Florida Statutes.

2. Florida Power & Light Company ("FPL") is the owner and operator of the Turkey Point Power Plant, and FPL is the owner and operator of approximately a 5,900-acre network of unlined canals (the "Cooling Canal System" or "CCS") on the FPL property described in the map in Exhibit A (the "Property").

3. In 1971, FPL signed a Consent Decree with the U.S. Department of Justice that required the construction, after permitting, of a closed-loop cooling configuration, with no discharge to surface waters.

4. The Florida Department of Pollution Control (later to become the Florida Department of Environmental Protection), in 1971, issued Construction Permit No. IC-1286 for the CCS. In 1972, Dade County issued Zoning Use Permit No. W-49833 for the excavation of the proposed Alternate Cooling Water Return Canal. FPL represents that in 1973, the construction of the CCS was completed; and the CCS was closed from the surface waters of both Biscayne Bay and Card Sound, becoming a closed-loop system.

5. An approximate 18 foot deep interceptor ditch located along the west side of the CCS was designed and constructed to create a hydraulic barrier to keep water in the CCS from migrating inland or westward.

6. In 1972, FPL entered into an agreement with the Central and Southern Florida Flood Control District (later to become the South Florida Water Management District or "District") addressing the operations and impacts of the CCS. The agreement has been updated several times, with the most recent version being the Fifth Supplemental Agreement between the District and FPL entered into on October 16, 2009 ("Fifth Supplemental Agreement") which included an extensive monitoring program for the CCS, entitled the Turkey Point Plant Groundwater, Surface Water and Ecological Monitoring Plan ("2009 Monitoring Plan"), incorporated as Exhibit A of the Fifth Supplemental Agreement.

7. In a letter dated April 16, 2013, the District notified FPL of their determination that saline water from the CCS has moved westward of the L-31E Canal in excess of those amounts that would have occurred without the existence of the CCS, and pursuant to the provisions of the Fifth Supplemental Agreement, initiated consultation with FPL for the mitigation, abatement or remediation of the saline water movement.

8. DERM issued a Notice of Violation dated October 2, 2015 (the "NOV") to FPL, alleging violations of Chapter 24 of the Code of Miami-Dade County, for alleged violations of County water quality standards and criteria in groundwater attributable to FPL's actions, and specifically for groundwaters outside the boundaries of FPL's Cooling Canal System and beyond the boundaries of the Property.

9. The phrase "hypersaline water" as used herein is defined as water that exceeds 19,000 mg/L chlorides.

10. DERM maintains there is hypersaline water attributable to FPL's actions in the groundwaters outside the boundaries of the Property, which exceeds County water quality standards and criteria. FPL acknowledges the presence of hypersaline water in certain areas outside the boundaries of the Property. For waters that do not reach the level of hypersalinity, DERM and FPL do not agree on the applicable "background" standards for chlorides.

11. In 2013 and 2014, FPL experienced water quality issues within the CCS, including increases in temperature and salinity, and FPL sought approvals from various regulatory agencies for actions to improve the water quality within the CCS.

12. DEP issued an Administrative Order, No. 14-0741, on December 23, 2014, requiring FPL to, among other things, reduce and maintain the annual average salinity of the CCS at a practical salinity of 34, and that Administrative Order is currently the subject of an Administrative Hearing.

13. Both DERM and FPL agree and acknowledge that it would be beneficial to improve the water quality within the Cooling Canal System itself, and FPL has already undertaken some efforts to improve the CCS water quality.

14. This Consent Agreement requires FPL to take action to address the County's alleged violations of County water quality standards and criteria in groundwaters outside the CCS as described in the NOV. As part of these actions, this Consent Agreement also requires FPL to take into account its efforts to improve CCS water quality and the potential and actual impacts of such actions on water resources outside the CCS, to not cause or contribute to (i) the exacerbation of alleged violations of County water quality standards or criteria or (ii) future violations of County water quality standards or criteria in the groundwaters or surface waters outside the CCS.

15. FPL hereby agrees to the terms of this Consent Agreement without admitting the allegations made by the above-mentioned NOV.

16. In an effort to expeditiously resolve this matter and to ensure compliance with Chapter 24 of the Code of Miami-Dade County, and to avoid time consuming and costly litigation, the parties hereto agree to the following, and it is ORDERED:

REQUIREMENTS

17. FPL shall undertake the following activities to specifically address water quality impacts associated with the CCS, as alleged in the NOV. The objective of this Consent Agreement will be for FPL to demonstrate a statistically valid reduction in the salt mass and volumetric extent of hypersaline water (as represented by chloride concentrations above 19,000 mg/L) in groundwater west and north of FPL's property without creating adverse environmental impacts. A further objective of this Consent Agreement is to reduce the rate of, and, as an ultimate goal, arrest migration of hypersaline groundwater. Recognizing other factors beyond FPL's control may influence movement of groundwater in the surficial aquifer, FPL shall reasonably take into account such factors when developing and implementing remedial actions to minimize the timeframe for achieving compliance with this Consent Agreement.

a. Abatement.

i. DERM acknowledges that FPL is planning to undertake the following:

1. pursue permitting, construction and operation of up to six Upper Floridan Aquifer System wells in accordance with the Site Certification Modification that is the subject of DOAH Case No. 15-1559EPP.

2. continue the use of the existing marine wells (SW-1, SW-2, and PW-1) as a short term resource to lower and maintain salinities. FPL shall work to avoid the use of the marine wells, except under extraordinary circumstances.

3. continue operation of the authorized L-31E canal pumps as a short term resource only, in accordance with the terms and conditions of the applicable approvals. FPL acknowledges that the use of water from the L-31E canal is intended only as a short term resource to lower CCS salinity. FPL anticipates the need for this resource for the next two years to reduce salinity as it transitions into the long term resources that are intended to maintain the lower salinity in the CCS. FPL acknowledges that additional regulatory

approvals will be required for continuation of this activity beyond the expiration of the existing approvals.

ii. FPL shall evaluate alternative water sources to offset the CCS water deficit and reduce chloride concentration in the CCS, and as a means of abating the westward movement of CCS groundwater. FPL will consider the practicality and appropriateness of using reclaimed wastewater from the Miami-Dade County South District Waste Water Treatment Plant as an alternative water source. FPL will provide DERM a summary of its Alternative Water Supply plan within 180 days of executing the Consent Agreement. FPL recognizes the importance and potential for reuse water, and FPL will make good faith efforts to implement the use of reuse water where practicable.

iii. FPL shall also conduct a review of the Interceptor Ditch operations to determine if current design and/or operations can be practicably modified to improve its function recognizing the current status of the CCS and surrounding wetlands. FPL will provide a summary of its Interceptor Ditch Review within 180 days of executing the Consent Agreement.

iv. The alternative water sources and any modifications to Interceptor Ditch design or operation shall be authorized through the appropriate regulatory processes and shall be demonstrated to not create adverse impacts to surface waters, groundwater, wetland or other environmental resources consistent with the Fifth Supplemental Agreement.

b. Remediation. FPL shall develop and implement the following actions to intercept, capture, contain, and retract hypersaline groundwater (groundwater with a chloride concentration of greater than 19,000 mg/L) to the Property boundary to achieve the objectives of this Consent Agreement.

i. Phase I. FPL shall design, permit, and construct a Biscayne Aquifer Recovery Well System (RWS) based on the results of a variable density dependent groundwater model which shall be sufficient to support the design of the RWS to intercept, capture, and contain the hypersaline plume; support authorization through the appropriate regulatory processes; and demonstrate that it will not create adverse impacts to groundwater, wetland (hydroperiod or water-stage), or other environmental resources. Final operation and design will be informed by an Aquifer Performance Test (APT). FPL shall provide its design and supporting information for the Recovery Well System and associated monitoring wells for DERM review and approval within 180 days of executing the Consent Agreement. FPL shall proceed with implementation within one year of executing the Consent Agreement, subject to regulatory timelines not in FPL's control. The initial design will be based on up to 12 MGD disposal capacity recognizing existing on-site capability. Efficacy of this design constraint will be reviewed in Phases 2, 3, and 4.

ii. Phase 2. FPL shall operate the RWS in accordance with all local, state, and federal regulatory requirements, collect data as required by the monitoring program, and employ the data to inform and reduce the uncertainty of the groundwater model. Status and efficacy of the system operation in meeting the objectives of this Consent Agreement and results of continued groundwater model refinement will be provided in the annual reports required in Paragraph 17d.

iii. Phase 3. After five years, FPL shall evaluate the effectiveness of the RWS in achieving the goal to intercept, capture, contain, and ultimately retract the hypersaline groundwater plume. This evaluation shall include estimated milestones and be based on the results of the monitoring data and refined groundwater/surfacewater model, which will be submitted to DERM. If the analysis indicates that the RWS is not anticipated to achieve the goal to intercept, capture, contain, and ultimately retract the hypersaline groundwater plume, FPL shall make recommendations for modifications to the project components and/or designs to ensure the ability of the system to achieve the objectives of the Consent Agreement. The evaluation and any proposed revisions shall be submitted to DERM for review and approval.

iv. Phase 4. After ten years, FPL shall review the results of the activities and progress to achieve the objectives of this Consent Agreement, and this evaluation shall be submitted to DERM. If monitoring demonstrates that the activities are not achieving the objectives of this Consent Agreement, FPL shall revise the project components and/or designs to ensure the ability of the system to achieve the objectives of this

Consent Agreement. The proposed revisions shall be submitted to DERM for review and approval.

c. Regional Hydrologic Improvement Projects. In addition, FPL agrees to undertake the following:

i. Raise control elevations in the Everglades Mitigation Bank. Within 30 days of the effective date of this Consent Agreement, FPL shall raise the control elevations of the FPL Everglades Mitigation Bank ("EMB") culvert weirs to no lower than 0.2 feet lower than the 2.4 foot trigger of the S-20 structure and shall maintain this elevation. After the first year of operation, FPL shall evaluate the change in control elevation, in regards to improvements in salinity, water quality, and lift in the area, and if FPL determines that the change in control elevations is not effective, or that FPL is negatively impacted in receiving mitigation credits as a result of this action, FPL will consult with DERM and propose potential alternatives.

ii. Fill portions of the Model Lands North Canal within the Everglades Mitigation Bank. Within 30 days of the effective date of the Consent Agreement, FPL shall seek all necessary regulatory approvals to place excavated fill from the adjoining roadway into the Model Lands North Canal within FPL's Everglades Mitigation Bank. Upon issuance of such regulatory approvals, FPL shall, starting on the east end, fill the Model Lands North Canal. This Consent Agreement only requires FPL to fill to the extent the fill is available from the adjoining roadway permitted to be degraded.

iii. If the District determines that flowage easements are needed from FPL in order to increase the operational stages of the S-20 water control structure as planned and approved by CERP, FPL agrees to provide such flowage easements for FPL owned land within the Everglades Mitigation Bank, in favor of the District within six months of the determination.

iv. FPL acknowledges the benefit of hydrologic restoration projects contemplated by the Comprehensive Everglades Restoration Project ("CERP"), as well as other government entities, adjacent and to the west of the CCS in controlling movement of hypersaline and saline waters in the Biscayne Aquifer. FPL commits to working with local, state and federal agencies to facilitate implementation of these projects to promote improved hydrologic conditions.

d. Monitoring and Reporting. FPL shall conduct monitoring to evaluate the progress made in achieving the objectives of this Consent Agreement. This includes actions that result from satisfying the abatement, remediation and hydrologic improvement components of this Consent Agreement. FPL shall initiate the monitoring and reporting requirements identified below within 30 days of executing the Consent Agreement. The monitoring shall include the following:

   i. FPL shall facilitate DERM access to all data from continuous electronically monitored stations.

   ii. FPL shall continue to provide monthly and quarterly reports substantially consistent with those required in M-D Class I permit CLI-2014-0312, beyond the expiration of the permit.

   iii. FPL shall employ Continuous Surface Electromagnetic Mapping (CSEM) methods to assess the location and orientation of the hypersaline plume west and north of the CCS.

   iv. FPL shall add three groundwater monitoring clusters (shallow, mid and deep) to monitor groundwater conditions in the model lands basin. The well clusters shall be similar in design and function to existing groundwater monitoring wells in the region as part of the CCS monitoring program, and shall be geographically located in consultation with DERM.

   v. FPL shall submit annual reports providing an evaluation of progress in achieving the objectives of this Consent Agreement, status of implementing projects identified above, and the results of monitoring to determine the impacts of these activities. Recommendations for refinements to the activities will be included in the annual report. This may include deletions of monitoring that is demonstrated to no longer be needed, or additional monitoring that is warranted based on observations.

SAFETY PRECAUTIONS

18. FPL shall maintain the subject property during the pendency of this Consent Agreement in a manner which shall not pose a hazard or threat to the public at large or the environment and shall not cause a nuisance or sanitary nuisance as set forth in Chapter 24 of the Code of Miami-Dade County, Florida.

VIOLATION OF REQUIREMENTS

19. This Consent Agreement constitutes a lawful order of the DERM Director and is enforceable in a civil court of competent jurisdiction. Violation of any requirement of this Consent Agreement may result in enforcement action by DERM. Each violation of any of the terms and conditions of this Consent Agreement by FPL shall constitute a separate offense.

SETTLEMENT COSTS

20. FPL hereby certifies that it has the financial ability to comply with the terms and conditions herein and to comply with the payment of settlement costs specified in this Agreement.

21. DERM has determined that due to the administrative costs incurred by DERM for this matter, a settlement of $30,000.00 is appropriate. FPL shall, within sixty (60) days of the effective date of this Consent Agreement, submit to DERM a check in the amount of $30,000.00 for full settlement payment. The payment shall be made payable to Miami-Dade County and sent to the Division of Environmental Resources Management, c/o Barbara Brown, 701 NW 1st Court, 6th Floor, Miami, FL 33136-3912.

22. In the event that FPL fails to submit, modify, implement, obtain, provide, operate and/or complete those items listed in paragraph 17 herein, FPL shall pay DERM a civil penalty of one hundred dollars ($100.00) per day for each day of non-compliance and FPL may be subject to enforcement action in a court of competent jurisdiction for such failure pursuant to those provisions set forth in Chapter 24 of the Code of Miami-Dade County. Any such payments shall be made by FPL to DERM within ten days of receipt of written notification and shall be sent to the Division of Environmental Resources Management, 701 NW 1st Court, 6th Floor, Miami, FL 33136-3912.

GENERAL PROVISIONS

23. FPL shall allow any duly authorized representative of DERM, with reasonable notification, to enter and inspect the CCS, Floridan wells, extraction wells, or any other relevant facilities, at any reasonable time for the purpose of ascertaining the state of compliance with the terms and conditions of this Consent Agreement. DERM shall comply with the plant safety and security precautions. FPL shall provide and maintain a point of contact at the Turkey Point Power Plant to assist DERM in accessing the facilities to be inspected.

24. On a quarterly basis (January, April, July, and October), DERM may collect surface and/or groundwater samples at the discretion of DERM at various monitoring locations in accordance with monitoring referenced in Paragraph 17 above.

25. FPL and DERM agree to cooperate and use best efforts moving forward related to this Consent Agreement.

26. Disputes related to or arising out of this Consent Agreement shall be construed consistent with the laws of the State of Florida and the United States, as applicable, and shall be filed in the state or federal courts of the State of Florida, as appropriate. Proceedings shall take place exclusively in the Circuit Court for Miami-Dade County, Florida or the United States District Court for the Southern District of Florida.

27. In consideration of the complete and timely performance by FPL of the obligations contained in this Consent Agreement, DERM waives its rights to seek judicial imposition of damages or civil penalties for the matters alleged in Notice of Violation and Consent Agreement.

28. Where FPL cannot meet timetables or conditions due to circumstances beyond FPL's control, FPL shall provide written documentation to DERM which shall substantiate that the cause(s) for delay or non-compliance was not reasonably in FPL's control. DERM shall make a determination of the reasonableness of the delay for the purpose of continued enforcement pursuant to paragraph 22 of this Consent Agreement.

29. DERM expressly reserves the right to initiate appropriate legal action to prevent or prohibit future violations of applicable laws, regulations, and ordinances or the rules promulgated thereunder.

30. Entry of this Consent Agreement does not relieve FPL of the responsibility to comply with applicable federal, state or local laws, regulations, and ordinances.

31. FPL acknowledges that this Consent Agreement is within the jurisdiction of Miami-Dade County. Nothing in this Consent Agreement is intended to expand, nor shall this Consent Agreement be construed to expand, the regulatory authority or jurisdiction of Miami-Dade County.

32. This Consent Agreement shall neither be evidence of a prior violation of this Chapter nor shall it be deemed to impose any limitation upon any investigation or action by DERM in the enforcement of Chapter 24 of the Code of Miami-Dade County.

33. This Consent Agreement shall become effective upon the date of execution by the DERM Director, or the Director's designee.

October 6, 2015
Date

Eric E. Silagy
President & CEO
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408
Respondent

Before me, the undersigned authority, personally appeared Eric Silagy, who after being duly sworn, deposes and says that they have read and agreed to the foregoing.

Subscribe and sworn to before me this 6th day of October, 2015 by Eric Silagy (name of affiant).

Personally known ✓ or Produced Identification ______.
(Check one)

Type of Identification Produced: ______________________.

LISA GROVE
MY COMMISSION # FF 154741
EXPIRES: December 14, 2018
Bonded Thru Budget Notary Services

Lisa Grove

Notary Public Signature

Lisa Grove

Notary Public Printed Name

DO NOT WRITE BELOW THIS LINE – GOVERNMENT USE ONLY

OCT 7 2015

Date

Lee N. Hefty, DERM Director

Miami-Dade County

Witness

Barbara Brown

Witness

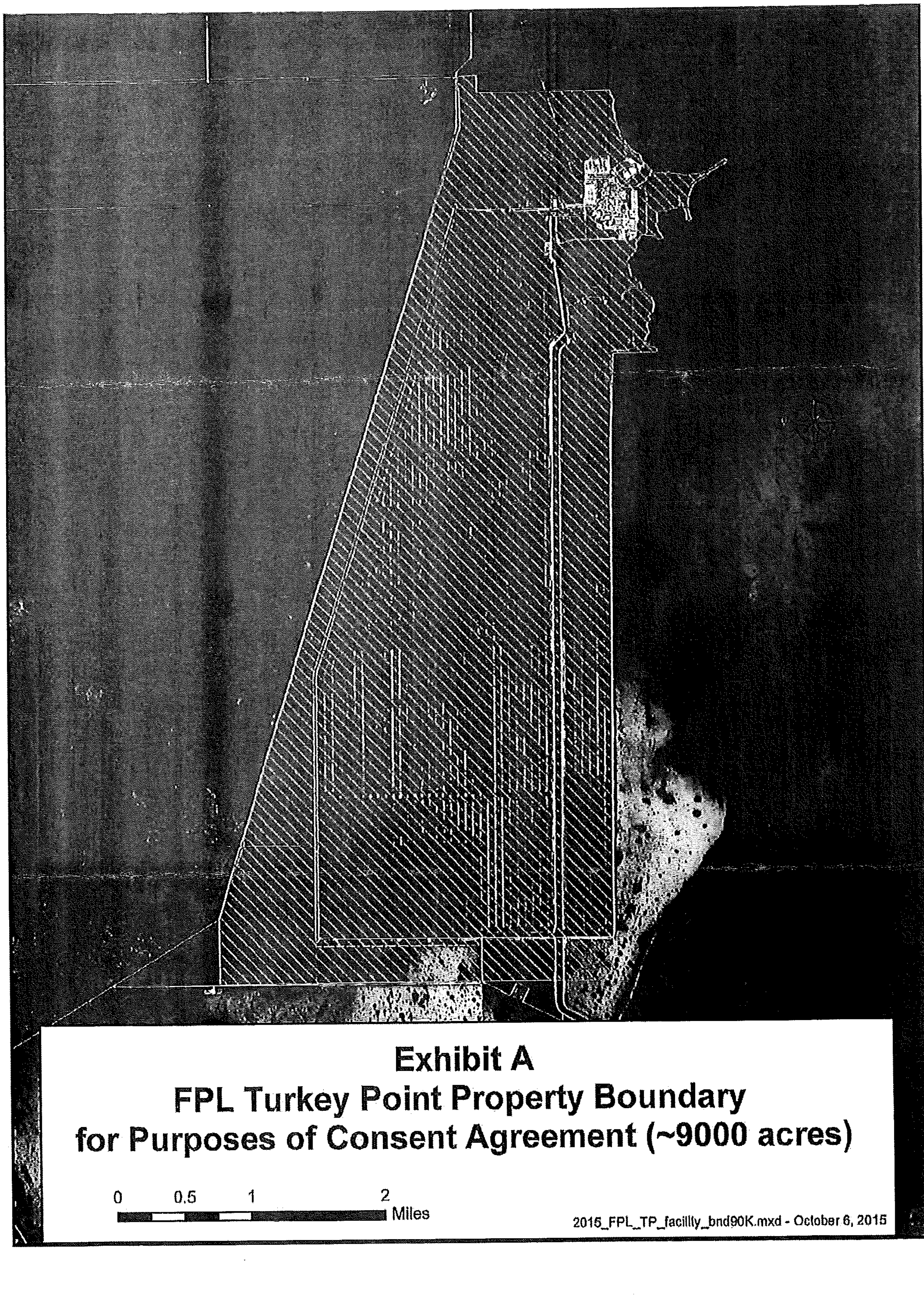
Exhibit A
FPL Turkey Point Property Boundary
for Purposes of Consent Agreement (~9000 acres)
0
0.5
1
2
Miles
2015_FPL_TP_facility_bnd90K.mxd - October 6, 2015

FPL TURKEY POINT SAMPLING RESULTS

MONITORING LOCATION (SAMPLE ID)	COLLECTION DATE & TIME	SECONDS	FIELD TEMPERATURE (°C)	ANALYTICAL METHOD USED	CHLOROPHYLL a (mg/m^3)	CHLORIDE (mg/L)	SULFATE (mg/L)	NITROGEN, KJELDAHL (mg/L)	NITRATE NITRITE as N (mg/L)	PHOSPHORUS as P (mg/L)	ORTHO-PHOSPHATE as P, DISSOLVED (mg/L)	COPPER (mg/L)	SODIUM (mg/L)	FIELD pH	OXYGEN (mg/L)	SALINITY (PSU)	SPECIFIC CONDUCTANCE (umhos/cm)	TOTAL DISSOLVED SOLIDS	TURBIDITY (NTU)	AMMONIA as N, (TOTAL AMMONIA NH_3+NH_4) (mg/L)	AMMONIA, IONIZED NH_4 (mg/L)	AMMONIA, UNIONIZED NH_3 (mg/L)

As of ____________

Date ____________

ADDENDUM 2 TO THE OCTOBER 7, 2015 CONSENT AGREEMENT
BETWEEN
MIAMI-DADE COUNTY DEPARTMENT OF REGULATORY AND ECONOMIC RESOURCES, DIVISION OF ENVIRONMENTAL RESOURCES MANAGEMENT
AND
FLORIDA POWER & LIGHT COMPANY

This Consent Agreement Addendum 2, entered into by and between Miami-Dade County Department of Regulatory and Economic Resources, Division of Environmental Resources Management (hereinafter referred to as "DERM"), and Florida Power & Light Company, (hereinafter referred to as "Respondent"), pursuant to Section 24-7(15)(c) of Chapter 24 of the Code of Miami-Dade County, shall serve to amend the October 7, 2015 Consent Agreement (Attachment 1) executed for the Turkey Point power plant facility and Cooling Canal System (CCS) located at, near or in the vicinity of 9700 SW 344 Street, Unincorporated, Miami-Dade County, Florida.

This Consent Agreement Addendum 2 serves to incorporate a revised Consent Agreement monitoring program. Therefore, DERM and the Respondent agree to modify Paragraph 17(d)(ii) of the October 7, 2015 Consent Agreement as follows:

ii. FPL shall monitor surface water and groundwater and perform ecological porewater monitoring as summarized in Exhibit B-Monitoring Network matrix effective October 1, 2018, which is attached hereto and made a part hereof. FPL shall facilitate DERM access, via FPL's EDMS, to data from all continuously electronically monitored stations pursuant to the revised Consent Agreement monitoring program. Additionally, analytical data shall be made available via FPL's EDMS within thirty (30) days of completion of laboratory QA/QC and data validation activities. FPL shall incorporate data from the revised monitoring program into the annual report required pursuant to Section 17.d.v of the October 7, 2015 Consent Agreement.

DERM and the Respondent also agree to modify Paragraph 17(d)(v) of the October 7, 2015 Consent Agreement as follows:

v. FPL shall submit annual reports providing an evaluation of progress in achieving the objectives of this Consent Agreement as amended, status of implementing projects identified above, and the results of monitoring to determine the impacts of these activities, including, for example, but not limited to, the information specified in item D of DERM's September 29, 2016 letter and any other applicable requirements resulting from the Consent Agreement Addendum dated August 15, 2016. Recommendations for refinements to the activities will be included in the annual report. This may include deletions of monitoring that is demonstrated to no longer be needed, or additional monitoring that is warranted based on observations. Any recommendations for refinement require DERM's approval prior to implementation.

All other provisions of the October 7, 2015 Consent Agreement and the August 15, 2016 Consent Agreement Addendum 1 shall remain unchanged and in full force and effect

[REMAINDER OF PAGE INTENTIONALLY BLANK; SIGNATURES APPEAR ON FOLLOWING PAGE]

8/14/2019
Date

Signature

Michael W. Sole V.P. Env.
Print Name and Title

Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408

Before me, the undersigned authority, personally appeared__________________________,

who after being duly sworn, deposes and says that he has read the foregoing.

Subscribed and sworn to before me this 14th day of August, 20 19 by
Michael W. Sole
(Name of affiant)

Personally Known ✓ or Produced Identification
(Check One)

Type of Identification Produced: ______________________________

Notary Public

Notary Public State of Florida
Fannie Strickland
My Commission FF 992597
Expires 05/15/2020

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8 - 20 - 2019
Date

Lee N. Hefty, Director
Environmental Resources Management

Witness

Witness

Station	Matrix	Sample Depth	Automated Parameters: Temperature, Specific Conductivity, Salinity and Stage	Field Analytical: Temperature, Specific Conductivity, Salinity, pH, Dissolved Oxygen, and Turbidity	Groundwater Analytic Lab Parameters: Cl, Na, Ca, K, SO4, Tritium, TAN, NH4, Nitrite/Nitrate, TKN, TN, TP, and OP	Surface Water Analytic Lab Parameters: Cl, Na, Tritium, TAN, NH4, NH3, Nitrite/Nitrate, TKN, TN, TP, and OP	Surface water Analytic Lab Parameter: Chlorophyll a	Induction Logging (deep well for TPGW Series wells); Temp, Sp. Cond. @ 1 ft intervals (for L & G series wells)
TPGW-1	Groundwater	S, M, D	Hourly	Quarterly	Quarterly	NA	NA	Annually
TPGW-2	Groundwater	S, M, D	Hourly	Quarterly	Quarterly	NA	NA	Annually
TPGW-3	Groundwater	S, M, D	Hourly	Quarterly	Quarterly	NA	NA	Annually
TPGW-4	Groundwater	S, M, D	Hourly	Quarterly	Quarterly	NA	NA	Annually
TPGW-5	Groundwater	S, M, D	Hourly	Quarterly	Quarterly	NA	NA	Annually
TPGW-6	Groundwater	S, M, D	Hourly	Quarterly	Quarterly	NA	NA	Annually
TPGW-7	Groundwater	S, M, D	Hourly	Quarterly	Quarterly	NA	NA	Annually
TPGW-8	Groundwater	Wells to be maintained operable and accessible						
TPGW-9	Groundwater							
TPGW-10	Groundwater	S, M, D	Hourly	Quarterly	Quarterly	NA	NA	Annually
TPGW-11	Groundwater	S, M, D	Hourly	Quarterly	Quarterly	NA	NA	Annually
TPGW-12	Groundwater	S, M, D	Hourly	Quarterly	Quarterly	NA	NA	Annually
TPGW-13	Groundwater	S, M, D	Hourly	Quarterly	Quarterly	NA	NA	Annually
TPGW-14	Groundwater	S, M, D	Hourly	Quarterly	Quarterly	NA	NA	Annually
TPGW-15	Groundwater	S, M, D	Hourly	Quarterly	Quarterly	NA	NA	Annually
TPGW-16	Groundwater	S, M, D	Hourly	Quarterly	Quarterly	NA	NA	Annually
TPGW-17	Groundwater	S, M, D	Hourly	Quarterly	Quarterly	NA	NA	Annually
TPGW-18	Groundwater	S, M, D	Hourly	Quarterly	Quarterly	NA	NA	Annually
TPGW-19	Groundwater	S, M, D	Hourly	Quarterly	Quarterly	NA	NA	Annually
L-3	Groundwater	18 ft, 58 ft	NA	Quarterly	Quarterly	NA	NA	Quarterly
L-5	Groundwater	18 ft, 58 ft	NA	Quarterly	Quarterly	NA	NA	Quarterly
G-21	Groundwater	18 ft, 58 ft	NA	Quarterly	Quarterly	NA	NA	Quarterly
G-28	Groundwater	18 ft, 58 ft	NA	Quarterly	Quarterly	NA	NA	Quarterly
TPSWC-1	Surface Water	T, B	Hourly(1)	Monthly	NA	Monthly	NA	NA
TPSWC-2	Surface Water	T, B	Hourly(1)	Monthly	NA	Monthly	NA	NA
TPSWC-3	Surface Water	T, B	Hourly(1)	Monthly	NA	Monthly	NA	NA
TPSWC-4	Surface Water	T, B	Hourly(1)	Monthly	NA	Monthly(2)	NA	NA
TPSWC-5	Surface Water	T, B	Hourly(1)	Monthly	NA	Monthly(2)	Monthly	NA
TPSWID-1	Surface Water	T, B	Hourly(1)	Monthly	NA	Monthly(2)	NA	NA
TPSWID-2	Surface Water	T, B	Hourly(1)	Monthly	NA	Monthly(2)	NA	NA
TPSWID-3	Surface Water	T, B	Hourly(1)	Monthly	NA	Monthly(2)	NA	NA
TPSWTESTC-1	Surface Water	B	Hourly(3)	Monthly	NA	Monthly	NA	NA
TPSWCCS-1	Surface Water	B	Hourly	Monthly	NA	Monthly(2)	Monthly	NA
TPSWCCS-6	Surface Water	T	Hourly	Monthly	NA	Monthly(2)	Monthly	NA
TPBBSW-4	Surface Water	B	Hourly(3)	Monthly	NA	Monthly	NA	NA
TPBBSW-6	Surface Water	T, B	Hourly(3)	Monthly	NA	Monthly	Monthly	NA
TPBBSW-7B	Discontinued effective 11/6/18 with commencement of Turtle Point canal restoration project. Station TPSWC-9 is the relocated station for Turtle Point canal.							
TPBBSW-7T	Surface Water	B	Hourly(3)	Monthly	NA	Monthly	Monthly	NA
TPSWC-9(4)	Surface Water	B	Hourly(3)	Monthly	NA	Monthly	Monthly	NA
F1-F5	Porewater	Physical parameters collected at 0, 30, 60 cm; Chemical parameters at 60 cm (where 60 cm cannot be attained, collect at deepest depth possible)	NA	Quarterly	NA	Quarterly	NA	NA

Station	Matrix	Sample Depth	Automated Parameters: Specific Conductivity, Salinity, Total Dissolved Solids, Volume, Flow, Salt Mass and Stage[5]	Field Analytical: Temperature, Specific Conductivity, Salinity, pH, Dissolved Oxygen, and Turbidity[6]	Laboratory Analytical Parameters Chloride ions, Ammonia, Ammonium Ion, Nitrite & Nitrate, Total Nitrogen, Total Kjeldahl Nitrogen, Total Phosphorus[5,6]	Surface Water Analytic Lab Parameters: Cl, Na, Tritium, TAN, NH4, NH3, Nitrite/Nitrate, TKN, TN, TP, and OP	Surface water Analytic Lab Parameter: Chlorophyll a	Induction Logging (deep well for TPGW Series wells); Temp, Sp. Cond. @ 1 ft intervals (for L & G series wells)
Groundwater Recovery Wells	Influent	NA	Hourly	Quarterly	Quarterly	NA	NA	NA

Note (1) Water elevations are measured from the top sampling interval only.
Note (2) Sample collection for Cu analysis one-week following any application of copper sulfate in the CCS, then monthly until two months after last treatment.
Note (3) Water elevation data not collected.
Note (4) Replacement station for TPBBSW-7B
Note (5) Parameters for Groundwater Recovery Well are different from those for Groundwater and Surface Water
Note (6) Frequency of monitoring may be adjusted, with DERM's approval, if there is minimal variation between RWS wells.

FPL

July 30, 2020

Mr. John J. Truitt
Deputy Secretary of Regulatory Programs
Florida Department of Environmental Protection
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

RE: Consent Order OGC File No. 16-0241 P. 20.a. Supplemental Salinity Management Plan

Dear Mr. Truitt:

The 2016 Consent Order ("CO") between Florida Power & Light Company ("FPL") and the Florida Department of Environmental Protection ("Department") outlines three objectives: (1) cease discharges from the Cooling Canal System ("CCS") that impair the reasonable and beneficial use of the adjacent G-II groundwater to the west of the CCS; (2) prevent releases of groundwater from the CCS to surface waters connected to Biscayne Bay that result in exceedances of surface water quality standards in the Bay; and (3) provide mitigation for impacts related to historic operation of the CCS. Since 2016, FPL has substantially accomplished the objectives of the CO and continues successful execution on all requirements within it. This letter serves to update the Department on FPL's successes under the CO and to provide a supplemental salinity management plan pursuant to condition 20.a that outlines additional measures, and timeframes, FPL will implement to achieve the salinity threshold.

Successes

Over the past year, FPL accomplished several milestones associated with the second and third objectives of the CO. Pursuant to objective two, we completed the Turtle Point and Barge Basin restoration project in May 2020. More than 200,000 cubic yards of clean beach quality sand was placed within the canals to restore the canal bathymetry and improve natural tidal circulation. In addition, more than 1,700 mangroves were planted in the newly created ~0.8-acre mangrove habitat within the Turtle Point canal. The mangrove habitat will provide additional foraging, breeding, and spawning habitat and improve the overall coastal ecosystem. Pursuant to objective three, FPL entered into an agreement with the South Florida Water Management District in April 2018 to convey to the District FPL property interests within the Biscayne Bay Coastal Wetlands Comprehensive Everglades Restoration Project footprint. In December 2019, several of those properties were conveyed to the District.

FPL has also accomplished a number of milestones associated with the CO's first objective. The CO includes a number of activities intended to accomplish this objective: freshening; eliminating the CCS contribution to the hypersaline plume; maintaining the average annual salinity of the CCS at or below 34 Practical Salinity Units ("PSU"); halting the westward migration of hypersaline water from the CCS; and reducing the westward extent of the hypersaline plume to the L-31E within 10 years.

To halt and retract the hypersaline groundwater west of the CCS, FPL constructed a recovery well system ("RWS") and began utilizing 10 wells in May 2018 to extract 15 MGD of hypersaline water. The RWS functions as a hydrological barrier that prevents the net movement of additional water from the CCS to locations in the aquifer west of the CCS. The RWS also functions to remove hypersaline water that migrated west of the CCS prior to installation of the recovery wells. After one year of operation, Continuous Surface Electromagnetic Mapping ("CSEM") showed a 22% reduction in the total volume of the hypersaline groundwater west and north of the CCS. As a result of all of FPL's actions, including interim extraction, FPL has removed over 8.4 billion pounds of salt from the Biscayne Aquifer since 2016.

To freshen the CCS, FPL installed five artesian-flowing Upper Floridan Aquifer wells to provide up to 14 MGD of brackish water to the CCS. In recent months, FPL also received approval to utilize a portion of Turkey Point Units 1-5's existing process water allocation to provide up to an additional 7 MGD of brackish Floridan Aquifer water to aid in CCS salinity reduction. These freshening measures have been instrumental in moderating CCS salinity over the three-and-a-half year freshening timeframe. Results from the agency-approved water and salt budget modeling show that the freshening to date has been effective in reducing the salinity in the CCS by over 20 PSU from levels that would have occurred had freshening measures not been implemented.

Supplemental Salinity Management Plan & Timeframes

Although FPL's freshening actions have been effective in moderating CCS salinity, we expect the average annual salinity to be above 34 PSU by November 28, 2020, the CO's timeframe for achieving the salinity threshold. CCS salinity is influenced by many factors, including, but not limited to, rainfall, air temperatures, and CCS evaporation rates. The CO recognizes these factors and includes a process to supplement CCS salinity reduction measures to achieve the salinity threshold. Specifically, CO Paragraph 20.a. indicates if FPL does not reach an average annual salinity of 34 PSU by the end of the fourth freshening year (November 28, 2020) then FPL must submit a plan within 30 days (December 28, 2020) detailing additional measures, and a timeframe, that will be implemented to achieve the salinity threshold. Therefore, and in advance of the December deadline, we are providing factors that affected CCS salinity during the freshening period and additional measures, and timeframes, FPL is undertaking to achieve the 34 PSU threshold ("Supplemental Salinity Management Plan" or "Plan"). FPL believes this Plan will increase CCS resilience and provide the much-needed operational flexibility to address variable conditions like rainfall and air temperature to achieve 34 PSU.

The salinity management plan originally presented to the Department in 2013 included an estimated freshening volume of 14 MGD of brackish groundwater needed to offset annual average CCS evaporative losses. The water and salt budget model used to support the initial freshening estimate utilized the best data available at the time, collected between 2010-2012. FPL now has a data record that covers a longer time period (2010-2019) and represents a wider range of hydrologic conditions. CCS salinity responses have shown that offsetting evaporative losses is more beneficial on a monthly basis, rather than on an annual average basis as used in the original modeling. By providing sufficient freshening to prevent dry season CCS salinity increases, combined with wet season surpluses, the net annual salinity will decrease in accordance with the requirements of the CO.

FPL analyzed the longer data record and utilized the agency-approved water and salt budget model to determine the additional brackish water beyond current allocations needed to offset evaporative losses and meet the CO's 34 PSU salinity threshold. We plan to undertake a number of actions as part of this Supplemental Salinity Management Plan to achieve the threshold and increase CCS resiliency.

In the near-term, we are maximizing our existing infrastructure and water use allocations to increase freshening volumes within permitted limits. Natural artesian pressure is currently producing approximately 11 of the 14 MGD allocation. Well maintenance was performed on four wells between March 2019 and May 2019 to improve well performance. Between 70% and 79% of the original well capacity was obtained from the effort, but more production is needed to reach 14 MGD. Therefore, FPL plans to install pumps on the permitted wells to reach the full allocation and provide an additional 3 MGD for CCS freshening by the end of the year.

FPL also plans to request a site certification modification to increase our brackish water allocation by 16 MGD, bringing the total freshening capacity to 30 MGD. This would include a monthly max allocation of 34 MGD to provide operational flexibility to offset monthly CCS evaporative losses. To inform the updated freshening volume needs, FPL evaluated the use of 30 MGD brackish water using the water and salt budget model. Absent a significant drought, the model indicates the 34 PSU annual average salinity threshold would be met by the end of the second year of freshening assuming similar hydrologic conditions to the dry conditions that occurred at the CCS in 2017 and 2018. Rainfall in South Florida is highly variable both seasonally and interannually. The previous nine-year record shows a wide range for rainfall year-to-year for any given month. In addition, review of nine years of monthly CCS rainfall and evaporation water budget data indicates evaporation exceeded rainfall by over 30 MGD 25% of the time in the period of record analyzed; therefore, the max month allocation of 34 MGD will allow for dynamic management of the allocation to offset the variation in monthly evaporative losses. The Plan considers natural variability and accordingly provides FPL operational flexibility to address changing conditions while improving CCS resiliency.

As part of the planning process, FPL examined whether the additional freshening would have any impact on seepage rates from the CCS. FPL used the agency-approved variable density flow and salt transport groundwater model for the calculations. The assessment determined that the increased freshening would result in a 0.1-foot stage increase in the CCS. However, as a result of the reduced fluid density of the 34 PSU CCS water, seepage rates to both the east and west will in fact be decreased compared with current conditions. The additional freshening will therefore have a positive impact on remediation of the hypersaline plume and will not hinder FPL's ability to meet its obligations under the CO to reduce the westward extent of the hypersaline plume to the L-31E within 10 years. The additional freshening will, as the modeling indicates, clearly help to remediate the hypersaline plume.

FPL is mindful of its water use and is using the lowest water quality source available (brackish water identified as an alternative water supply source by the South Florida Water Management District) for freshening, process, and cooling water purposes at Turkey Point. We are requesting the use of additional brackish water because we believe it is the best solution to manage salinity and will not negatively impact existing legal users. FPL will include a water conservation plan in our site certification modification that will adjust the amount of brackish water use once the 34 PSU threshold is achieved. FPL has also continued to build the foundation for a partnership with Miami-Dade County to treat up to 15 MGD of reclaimed water at Turkey Point for the Unit 5 cooling towers (see June 2020 Miami-Dade Board of County Commissioners Resolution No. R-579-20). This opportunity will help Miami-Dade County meet state reuse requirements while also replacing the brackish Floridan groundwater as a primary source for Unit 5 cooling purposes, reducing Unit 5 groundwater withdrawals. This will offset site-wide use of brackish water.

FPL is proud of our successes in implementing the Consent Order. As contemplated by the CO, we have used the over 4.5 million data points gathered annually to analyze the outcomes of our actions and make adjustments as necessary. We believe the supplemental actions we are undertaking and proposing will allow us to achieve our remaining targets under the CO, and we are proud of Turkey Point's safe delivery of greenhouse gas free power for almost fifty years.

FPL intends to submit the site certification modification application in the third quarter of 2020 and expects to complete permitting and implement the increased freshening allocation in the second quarter of 2021. As part of the application, we will provide additional back-up information, including updated data and models, to support the request. We would like to meet with the Department to discuss the Plan in preparation for our site certification modification request. If these discussions yield additional measures, FPL will update the Department prior to the December 28, 2020 deadline.

Should you have any questions, please do not hesitate to call me at 561-691-2406.

Sincerely,

Danielle L. Hall
Environmental Services Manager

CC:
Marc Harris, FDEP
Allan Stodghill, FDEP
Cindy Mulkey, FDEP
Lee Hefty, MDC
Drew Bartlett, SFWMD

Department of Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Jeb Bush
Governor

Colleen M. Castille
Secretary

In the Matter of an
Application for Permit by:

CERTIFIED MAIL
RETURN RECIEPT REQUESTED

Turkey Point Power Plant
9760 S.W. 344 Street
Florida City, FL 34428

DEP File # FL0001562-004-IW1N/NR
Miami-Dade County
Florida Power & Light Company

Attention: Mr. Terry O. Jones

NOTICE OF PERMIT

Enclosed is Permit Number FL0001562, issued under Section 403.0885, Florida Statutes and DEP Chapter 62-620, Florida Administrative Code, authorizing renewal of a "No Discharge" NPDES permit for internal discharge to an onsite closed-loop recirculating cooling canal system at the Turkey Point Power Plant located at 9670 S.W. 344 Street, Florida City, Miami-Dade County, Florida.

Any party to this order (permit) has the right to seek judicial review of the permit under section 120.68 of the Florida Statutes, by the filing of a Notice of Appeal under rule 9.110 of the Florida Rules of Appellate Procedure, with the Clerk of the Department of Environmental Protection, Office of General Counsel, Mail Station 35, 3900 Commonwealth Boulevard, Tallahassee, Florida 32399-3000 and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate district court of appeal. The notice of appeal must be filed within thirty days after this notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Mimi Drew

Mimi Drew
Director
Division of Water Resource Management
2600 Blair Stone Road
Tallahassee, FL 32399-2400
(850) 245-8336

FILING AND ACKNOWLEDGMENT

FILED, on this date, under Section 120.52, Florida Statutes, with the designated deputy clerk, receipt of which is hereby acknowledged.

C. Shields 05-13-05

Clerk Date

Copies furnished to:

Roosevelt Childress, EPA
Chairman, Miami-Dade County Board of Commissioners
Tim Powell, P.E., DEP SED, West Palm Beach
Buck Oven, P.E., DEP Tallahassee
Betsy Hewitt, DEP Tallahassee (w/o enclosure)

SECOND AMENDMENT TO THE FACT SHEET

DATE: January 28, 2004

PERMIT NUMBER: FL0001562

PERMITTEE: Florida Power & Light Company
Turkey Point Power Plant

The following minor corrections have been made to the proposed permit. None of these corrections alter any of the discharge limitations monitoring requirements in the permit.

1. Permittee Comments

The Permittee requested the following minor corrections to the permit.

Typographical errors in the Draft Permit: The Applicant pointed out several typographical errors by the Department which are not listed in the items below. The Department has corrected these errors, which were non-substantive and did not affect any permit limitations or monitoring requirements.

Condition I.A.6.&7. The Permittee pointed out that that previous permits did not include these conditions, which refer to floating foam and visible sheen on surface waters of the state due to discharge of wastewater. The Permittee noted that the conditions are not appropriate because the facility does not discharge to surface waters. The Department concurs, and notes that it included the conditions in error. The conditions have been deleted from the final permit.

STATE OF FLORIDA
INDUSTRIAL WASTEWATER FACILITY PERMIT

PERMITTEE:

Florida Power & Light Company
9760 S.W. 344 Street
Florida City, FL 33035

PERMIT NUMBER: FL0001562 (Major)
PA FILE NUMBER: FL0001562-004-IW1N
ISSUANCE DATE: May 6, 2005
EXPIRATION DATE: May 5, 2010

RESPONSIBLE AUTHORITY:

Mr. Terry O. Jones
Vice President

FACILITY:

FPL Turkey Point Power Plant
9760 S.W. 344 Street
Florida City, FL 33035
Dade County

Latitude: See Note Below Longitude: See Note Below

Note: Latitude and longitude are not shown at Permittee's request, for purposes of Homeland Security pursuant to federal regulations found at 18 CFR 388.113(c)(i) and (ii) and by Presidential Directive dated December 17, 2003.

This permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.) and applicable rules of the Florida Administrative Code (F.A.C.), and constitutes authorization to discharge to waters of the state under the National Pollutant Discharge Elimination System (NPDES). The above named permittee is hereby authorized to operate the facilities shown on the application and other documents attached hereto or on file with the Department and made a part hereof and specifically described as follows:

The facility consists of four steam-electric generating units: Two fossil fuel oil-fired units (Units 1&2) and two nuclear units (Units 3&4). Units 1&2 each have a continuous generating capability of 404 megawatts (MW), and Units 3&4 each have a continuous generating capability of 693 MW.

WASTEWATER TREATMENT:

Wastewater from the Turkey Point facility consists of a non-contact once-through condenser cooling water (OTCW), auxiliary equipment cooling water (AECW), low-volume waste (LVW), and stormwater. LVW consists of chemical treatment system wastewater, boiler blowdown, reverse osmosis concentrate, condensate polishing system backwash water, and other process wastestreams. Stormwater includes stormwater associated with industrial activity and stormwater not associated with industrial activity.

OTCW and AECW discharge to the facility's approximately 6,700 acre onsite closed loop cooling canal system. LVW, equipment area stormwater, and non-equipment area stormwater/drainage discharge either directly to the onsite closed loop cooling canal system or indirectly to the same system via solids settling basins and/or neutralization basin. The cooling canal system is not lined, and therefore, discharges to Class G-III groundwater. The cooling canal system does not discharge to surface waters of the state.

PERMITTEE:	PERMIT NUMBER:	FL0001562
Florida Power & Light Company 9760 S.W. 344 Street Florida City, FL 33035	Issuance date: Expiration date:	May 6, 2005 May 5, 2010

EFFLUENT DISPOSAL:

Surface Water Discharge:

This permit does not authorize discharge to surface waters of the state.

Internal Outfalls:

This permit authorizes discharge from existing internal outfalls I-001 and I-002 to the facility's onsite closed loop cooling canal system.

Groundwater Discharge

This permit authorizes an existing discharge from the onsite closed loop cooling canal system to the surficial aquifer which is a Class G-III groundwater.

IN ACCORDANCE WITH: The limitations, monitoring requirements and other conditions as set forth in Part I through Part VIII on pages 3 through 14 of this permit.

PERMITTEE:	PERMIT NUMBER:	FL0001562
Florida Power & Light Company 9760 S.W. 344 Street Florida City, FL 33035	Issuance date: Expiration date:	May 6, 2005 May 5, 2010

I. Effluent Limitations and Monitoring Requirements

A. Surface Water Discharges

1. This permit does not authorize discharge to surface waters of the state.

2. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge non process wastewater consisting of non-contact once-through condenser cooling water (OTCW), non-contact auxiliary equipment cooling water (AECW), and other wastestreams (as indicated in the permit renewal application) from Internal Outfall I-001 to the onsite feeder canal within the facility's onsite closed loop cooling canal system. Such discharge shall be limited and monitored by the permittee as specified below:

	Discharge Limitations			Monitoring Requirements		
Parameters (units)	**Maximum Daily Average**	**Daily Maximum**	**Daily Minimum**	**Monitoring Frequency**	**Sample Type**	**Sample Point**
Temperature (F), Water (DEG.F)	--	Report	--	Monthly	Instantaneous	OUI-1
Solids, Total Suspended (MG/L)	--	Report	--	Quarterly	Grab	OUI-1
pH (SU)	--	Report	Report	Quarterly	Grab	OUI-1
Salinity (PPT)	--	Report	--	Quarterly	Grab	OUI-1
Specific Conductance (UMHO/CM)	--	Report	--	Quarterly	Grab	OUI-1
Copper, Total Recoverable (UG/L)	--	Report	--	Semiannually	Grab	OUI-1
Iron, Total Recoverable (MG/L)	--	Report	--	Semiannually	Grab	OUI-1
Zinc, Total Recoverable (UG/L)	--	Report	--	Semiannually	Grab	OUI-1

3. Effluent samples shall be taken at the monitoring site locations listed in permit condition I.A.2. and as described below:

Sample Point	**Description of Monitoring Location**
OUI-1	Cooling water discharge prior to entering the feeder canal within the closed loop cooling canal system

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4. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge process wastewater and stormwater from Internal Outfall I-002 into the facility's onsite closed loop cooling canal system. Such discharge shall be limited and monitored by the permittee as specified below:

	Discharge Limitations			Monitoring Requirements		
Parameters (units)	**Monthly Average**	**Daily Maximum**	**Daily Minimum**	**Monitoring Frequency**	**Sample Type**	**Sample Point**
Solids, Total Suspended (MG/L)	--	Report	--	Semiannually	Grab	OUI-2
PH (SU)	--	Report	Report	Monthly	Grab	OUI-2
Specific Conductance (UMHO/CM)	--	Report	--	Quarterly	Grab	OUI-2
Lead, Total Recoverable (UG/L)	--	Report	--	Semiannually	Grab	OUI-2
Oil and Grease (MG/L)	--	Report	--	Semiannually	Grab	OUI-2
Copper, Total Recoverable (UG/L)	--	Report	--	Semiannually	Grab	OUI-2
Zinc, Total Recoverable (UG/L)	--	Report	--	Semiannually	Grab	OUI-2

5. Effluent samples shall be taken at the monitoring site locations listed in permit condition I.A.4. and as described below:

Sample Point	Description of Monitoring Location
OUI-2	discharge from the two solids settling basins or neutralization basin prior to mixing with water in the closed loop cooling canal system

B. Underground Injection Control Systems

1. This section is not applicable to this permit. Discharge by underground injection is regulated under permit UC-13-277655.

C. Land Application Systems

1. This section is not applicable to this facility.

D. Other Methods of Disposal or Recycling

1. There shall be no discharge of industrial wastewater from this facility to ground or surface waters, except as authorized by this permit.

E. Other Limitations and Monitoring and Reporting Requirements

1. Monitoring requirements under this permit are effective on the first day of the second month following permit issuance. Until such time, the permittee shall continue to monitor and report in accordance with previously effective permit requirements, if any. During the period of operation authorized by this permit, the permittee shall complete and submit to the Southeast District Office Discharge Monitoring Reports (DMRs) in accordance

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with the frequencies specified by the REPORT type (i.e., monthly, toxicity, quarterly, semiannual, annual, etc.) indicated on the DMR forms attached to this permit. Monitoring results for each monitoring period shall be submitted in accordance with the associated DMR due dates below.

REPORT Type on DMR	Monitoring Period	DMR Due Date
Monthly or Toxicity	first day of month – last day of month	28th day of following month
Quarterly	January 1 - March 31 April 1 – June 30 July 1 – September 30 October 1 – December 31	April 28 July 28 October 28 January 28
Semiannual	January 1 – June 30 July 1 – December 31	July 28 January 28
Annual	January 1 – December 31	January 28

DMRs shall be submitted for each required monitoring period including months of no discharge.

The permittee shall make copies of the attached DMR form(s) and shall submit the completed DMR form(s) to the Department's Southeast District Office at the address specified in Permit Condition I.E.2.

2. Unless specified otherwise in this permit, all reports and notifications required by this permit, including twenty-four hour notifications, shall be submitted to or reported to the Southeast District Office at the address specified below:

   Southeast District Office
   400 North Congress, Suite 200
   West Palm Beach, FL 33401-3303

   Phone Number - (561) 681-6702

3. All reports and other information shall be signed in accordance with requirements of Rule 62-620.305, F.A.C.

4. The permittee shall provide safe access points for obtaining representative samples which are required by this permit.

5. If there is no discharge from the facility on a day scheduled for sampling, the sample shall be collected on the day of the next discharge.

6. Bypasses subject to General Conditions VIII.20 and VIII.22 shall be monitored or estimated daily, or as approved by the Department for flow and other parameters required for the specific outfall that is bypassed. Monitoring results shall be reported to the Department.

7. There shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid.

8. This permit authorizes the use of the following biocides, or their generic equivalents, in various closed cooling water systems without limitations or monitoring; NALCO 7338, NALCO 7330, NALCO 7348, BULAB 6001/6002, BETZ POWERLINE 3610. The Permittee shall notify the Department if there is a discharge of any of these products into the closed cycle cooling canal system in other than de-minimus amounts which contain concentrations of active ingredients above the MDLs for those ingredients.

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9. A permit revision from the Department shall be required prior to the use of any biocide or chemical additive, which may be toxic to aquatic life, (except as authorized elsewhere in this permit) in the cooling water system or any other portion of the industrial wastewater system. The permit revision request shall include:

   a. Name and general composition of biocide or chemical
   b. Frequencies of use
   c. Quantities to be used
   d. Proposed effluent concentrations
   e. Acute and/or chronic toxicity data (laboratory reports shall be prepared according to Section 12 of EPA document no. EPA/600/4-90/027 entitled, Methods for Measuring the Acute Toxicity of Effluents and Receiving Waters for Freshwater and Marine Organisms, or most current addition.)
   f. Product data sheet
   g. Product label

   The Department shall review the above information to determine if a major or minor permit revision is necessary. Discharge associated with the use of such biocide or chemical is not authorized without prior authorization by the Department. Permit revisions shall be processed in accordance with the requirements of Chapter 62-620, F.A.C.

10. Discharge of any product registered under the Federal Insecticide, Fungicide, and Rodenticide Act to any waste stream which ultimately may be released to waters of the State is prohibited unless specifically authorized elsewhere in this permit. This requirement is not applicable to products used for lawn and agricultural purposes or to the use of herbicides if used in accordance with labeled instructions and any applicable State permit.

11. Hydrazine and Monoethanolamine (ETA) Monitoring Requirements

    a) Discharge of hydrazine, carbohydrazide, dimethylamine, and monoethanolamine (ETA) in the boiler or steam generator blowdown is authorized without limitation or monitoring requirements.
    b) Hydrazine from plant layup water during overhauls and/or refueling outages shall be measured at the outlet from the unit being serviced. Sampling shall be once per day of discharge by grab sample at the maximum expected concentration. Results of sampling will be submitted to the Department upon request. To determine the hydrazine concentration being discharged to the cooling canal system, the following equation shall be used:

$$\frac{\textit{(B/S) Blowdown Flow x (B/S) Hydrazine Concentration}}{\textit{Once-through Cooling Water Flow}} = \textit{Hydrazine concentration at the closed cycle cooling canal system}$$

    Where (B/S) refers to boiler or steam generator

    In the event that any value exceeds 3.4 mg/l, the permittee shall immediately modify its release pattern and resample. The Department's Southeast District office will be notified of the situation within five days.

12. Molybdate, Tolytriazole, and Nitrite Discharge Requirements
    The discharge of molybdate, tolytriazole, and nitrite to the closed cycle recirculating cooling canal system during maintenance of the auxiliary closed water system is allowed without limitations and monitoring requirements.

13. Non-discharging/Closed Loop Vehicle Wash Recycle System Requirements

    a) No discharge of recycle system wastewater, including filter backwash water, is authorized to surface water or to ground water.

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b) The rainwater diversion system shall be operated in accordance with the facility's Best Management Practice Procedure as indicated on amended drawing No. 297-036, Alternate No. 6, signed and sealed 4/23/99.

c) A placard shall be conspicuously posted in the area of the non-discharging/closed loop recycle equipment which indicates the proper operation of the rainwater diversion system i.e. TRUCK WASH RAINWATER VALVE OPERATING PROCEDURE as indicated on amended drawing No. 297-036 Alternate No. 6, signed and sealed 4/23/99.

d) d) Spent process wastewater shall be disposed of at a Department permitted wastewater treatment facility which is capable of treating the wastewater.

e) Any oil collected from the oil/water separator shall be disposed by a licensed used oil recycler in accordance with Florida Administrative Code 62-710 or otherwise recycled on site through Department approved methods and procedures.

f) Any accidental discharge to ground water or surface water shall be reported to the Southeast District office.

14. Notwithstanding any other requirements of this "No Discharge" permit, the permittee shall comply with all applicable provisions of the Final Judgement dated September 10, 1971, in Civil Action Number 70-328-CA issued by the U.S. District Judge C. Clyde Atkins of the Southern District of Florida.

II. Industrial Sludge Management Requirements

A. Basic Management Requirements

1. Sludge or other solids generated from the facility shall be reused, reclaimed, or otherwise disposed of in accordance with the requirements of Chapter 62-701, F.A.C.

2. The permittee shall keep records at the facility of the amount of sludge or residuals disposed, transported, or incinerated. If a person other than the permittee is responsible for sludge transporting, disposal, or incineration, the permittee shall also keep the following records:

   a. name, address and telephone number of any transporter, and any manifests or bill of lading used;
   b. name and location of the site of disposal, treatment or incineration;
   c. name, address, and telephone number of the entity responsible for the disposal, treatment, or incineration site.

III. Ground Water Monitoring Requirements

1. This section is not applicable to this facility.

IV. Other Land Application Requirements

1. The Permittee's discharge to ground water shall not cause a violation of the minimum criteria for ground water specified in Rule 62-520.400, F.A.C. and 62-520.430, F.A.C.

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V. Operation and Maintenance Requirements

A. Operation of Treatment and Disposal Facilities

1. The permittee shall ensure that the operation of this facility is as described in the application and supporting documents.

2. The operation of the pollution control facilities described in this permit shall be under the supervision of a person who is qualified by formal training and/or practical experience in the field of water pollution control.

B. Record keeping Requirements:

1. The permittee shall maintain the following records on the site of the permitted facility and make them available for inspection:

   a. Records of all compliance monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, including, if applicable, a copy of the laboratory certification showing the certification number of the laboratory, for at least three years from the date the sample or measurement was taken;

   b. Copies of all reports, other than those required in items a. and f. of this section, required by the permit for at least three years from the date the report was prepared, unless otherwise specified by Department rule;

   c. Records of all data, including reports and documents used to complete the application for the permit for at least three years from the date the application was filed, unless otherwise specified by Department rule;

   d. A copy of the current permit;

   e. A copy of any required record drawings;

   f. Copies of the logs and schedules showing plant operations and equipment maintenance for three years from the date on the logs or schedule.

VI. Schedules

1. The permittee shall achieve compliance with the other conditions of this permit as follows:

Operational level attained	Issuance Date of permit

2. No later than 14 calendar days following a date identified in the above schedule(s) of compliance, the permittee shall submit either a report of progress or, in the case of specific actions being required by an identified date, a written notice of compliance or noncompliance. In the latter case, the notice shall include the cause of noncompliance, any remedial actions taken, and the probability of meeting the next scheduled requirement.

VII. Other Specific Conditions

A. Specific Conditions Applicable to All Permits

1. Drawings, plans, documents or specifications submitted by the permittee, not attached hereto, but retained on file at the Southeast District Office, are made a part hereof.

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2. Where required by Chapter 471 (P.E.) or Chapter 492 (P.G.) Florida Statutes, applicable portions of reports to be submitted under this permit, shall be signed and sealed by the professional(s) who prepared them.

3. This permit satisfies Industrial Wastewater program permitting requirements only and does not authorize operation of this facility prior to obtaining any other permits required by local, state or federal agencies.

B. Specific Conditions Related to Construction

1. This section is not applicable to this facility.

C. Duty to Reapply

1. The permittee shall submit an application to renew this permit at least 180 days before the expiration date of this permit.

2. The permittee shall apply for renewal of this permit on the appropriate form listed in Rule 62-620.910, F.A.C., and in the manner established in Chapter 62-620, F.A.C., and the Department of Environmental Protection Guide to Wastewater Permitting including submittal of the appropriate processing fee set forth in Rule 62-4.050, F.A.C.

3. An application filed in accordance with subsections 1. and 2. of this part shall be considered timely and sufficient. When an application for renewal of a permit is timely and sufficient, the existing permit shall not expire until the Department has taken final action on the application for renewal or until the last day for seeking judicial review of the agency order or a later date fixed by order of the reviewing court.

4. The late submittal of a renewal application shall be considered timely and sufficient for the purpose of extending the effectiveness of the expiring permit only if it is submitted and made complete before the expiration date.

D. Specific Conditions Related to Existing Manufacturing, Commercial, Mining, and Silviculture Wastewater Facilities or Activities

1. Existing manufacturing, commercial, mining, and silvicultural wastewater facilities or activities that discharge into surface waters shall notify the Department as soon as they know or have reason to believe:

   a. That any activity has occurred or will occur which would result in the discharge, on a routine or frequent basis, of any toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the following levels
      (1) One hundred micrograms per liter,
      (2) Two hundred micrograms per liter for acrolein and acrylonitrile; five hundred micrograms per liter for 2,4-dinitrophenol and for 2-methyl-4,6-dinitrophenol; and one milligram per liter for antimony, or
      (3) Five times the maximum concentration value reported for that pollutant in the permit application.

   b. That any activity has occurred or will occur which would result in any discharge, on a non-routine or infrequent basis, of a toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the following levels
      (1) Five hundred micrograms per liter,
      (2) One milligram per liter for antimony, or
      (3) Ten times the maximum concentration value reported for that pollutant in the permit application.

E. Reopener Clause

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1. The permit shall be revised, or alternatively, revoked and reissued in accordance with the provisions contained in Rules 62-620.325 and 62-620.345 F.A.C., if applicable, or to comply with any applicable effluent standard or limitation issued or approved under Sections 301(b)(2)(C) and (D), 304(b)(2) and 307(a)(2) of the Clean Water Act (the Act), as amended, if the effluent standards, limitations, or water quality standards so issued or approved:

   a. Contains different conditions or is otherwise more stringent than any condition in the permit/or;

   b. Controls any pollutant not addressed in the permit.

   The permit as revised or reissued under this paragraph shall contain any other requirements then applicable.

2. The permit may be reopened to adjust effluent limitations or monitoring requirements should future Water Quality Based Effluent Limitation determinations, water quality studies, DEP approved changes in water quality standards, or other information show a need for a different limitation or monitoring requirement.

3. The Department may develop a Total Maximum Daily Load (TMDL) during the life of the permit. Once a TMDL has been established and adopted by rule, the Department shall revise this permit to incorporate the final findings of the TMDL.

VIII. General Conditions

1. The terms, conditions, requirements, limitations and restrictions set forth in this permit are binding and enforceable pursuant to Chapter 403, F.S. Any permit noncompliance constitutes a violation of Chapter 403, F.S., and is grounds for enforcement action, permit termination, permit revocation and reissuance, or permit revision. *[62-620.610(1), F.A.C.]*

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications or conditions of this permit constitutes grounds for revocation and enforcement action by the Department. *[62-620.610(2), F.A.C.]*

3. As provided in Subsection 403.087(6), F.S., the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor authorize any infringements of federal, state, or local laws or regulations. This permit is not a waiver of or approval of any other Department permit or authorization that may be required for other aspects of the total project which are not addressed in this permit. *[62-620.610(3), F.A.C.]*

4. This permit conveys no title to land or water, does not constitute state recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title. *[62-620.610(4), F.A.C.]*

5. This permit does not relieve the permittee from liability and penalties for harm or injury to human health or welfare, animal or plant life, or property caused by the construction or operation of this permitted source; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department. The permittee shall take all reasonable steps to minimize or prevent any discharge, reuse of reclaimed water, or residuals use or disposal in violation of this permit which has a reasonable likelihood of adversely affecting human health or the environment. It shall not be

a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. *[62-620.610(5), F.A.C.]*

6. If the permittee wishes to continue an activity regulated by this permit after its expiration date, the permittee shall apply for and obtain a new permit. *[62-620.610(6), F.A.C.]*

7. The permittee shall at all times properly operate and maintain the facility and systems of treatment and control, and related appurtenances, that are installed and used by the permittee to achieve compliance with the conditions of this permit. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to maintain or achieve compliance with the conditions of the permit. *[62-620.610(7), F.A.C.]*

8. This permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the permittee for a permit revision, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance does not stay any permit condition. *[62-620.610(8), F.A.C.]*

9. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, including an authorized representative of the Department and authorized EPA personnel, when applicable, upon presentation of credentials or other documents as may be required by law, and at reasonable times, depending upon the nature of the concern being investigated, to
   a. Enter upon the permittee's premises where a regulated facility, system, or activity is located or conducted, or where records shall be kept under the conditions of this permit;
   b. Have access to and copy any records that shall be kept under the conditions of this permit;
   c. Inspect the facilities, equipment, practices, or operations regulated or required under this permit; and
   d. Sample or monitor any substances or parameters at any location necessary to assure compliance with this permit or Department rules.

   [62-620.610(9), F.A.C.]

10. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data, and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except as such use is proscribed by Section 403.111, Florida Statutes, or Rule 62-620.302, F.A.C. Such evidence shall only be used to the extent that it is consistent with the Florida Rules of Civil Procedure and applicable evidentiary rules. *[62-620.610(10), F.A.C.]*

11. When requested by the Department, the permittee shall within a reasonable time provide any information required by law which is needed to determine whether there is cause for revising, revoking and reissuing, or terminating this permit, or to determine compliance with the permit. The permittee shall also provide to the Department upon request copies of records required by this permit to be kept. If the permittee becomes aware of relevant facts that were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be promptly submitted or corrections promptly reported to the Department. *[62-620.610(11), F.A.C.]*

12. Unless specifically stated otherwise in Department rules, the permittee, in accepting this permit, agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance; provided however, the permittee does not waive any other rights granted by Florida Statutes or Department rules. A reasonable time for compliance with a new or amended surface water quality standard, other than those standards addressed in Rule 62-302.500, F.A.C., shall include a reasonable time to obtain or be denied a mixing zone for the new or amended standard. *[62-620.610(12), F.A.C.]*

13. The permittee, in accepting this permit, agrees to pay the applicable regulatory program and surveillance fee in accordance with Rule 62-4.052, F.A.C. *[62-620.610(13), F.A.C.]*

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14. This permit is transferable only upon Department approval in accordance with Rule 62-620.340, F.A.C. The permittee shall be liable for any noncompliance of the permitted activity until the Department approves the transfer. *[62-620.610(14), F.A.C.]*

15. The permittee shall give the Department written notice at least 60 days before inactivation or abandonment of a wastewater facility and shall specify what steps will be taken to safeguard public health and safety during and following inactivation or abandonment. *[62-620.610(15), F.A.C.]*

16. The permittee shall apply for a revision to the Department permit in accordance with Rule 62-620.300, F.A.C., and the Department of Environmental Protection Guide to Wastewater Permitting at least 90 days before construction of any planned substantial modifications to the permitted facility is to commence or with Rule 62-620.325(2), F.A.C., for minor modifications to the permitted facility. A revised permit shall be obtained before construction begins except as provided in Rule 62-620.300, F.A.C. *[62-620.610(16), F.A.C.]*

17. The permittee shall give advance notice to the Department of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements. The permittee shall be responsible for any and all damages which may result from the changes and may be subject to enforcement action by the Department for penalties or revocation of this permit. The notice shall include the following information:
    a. A description of the anticipated noncompliance;
    b. The period of the anticipated noncompliance, including dates and times; and
    c. Steps being taken to prevent future occurrence of the noncompliance.
    [62-620.610(17), F.A.C.]

18. Sampling and monitoring data shall be collected and analyzed in accordance with Rule 62-4.246, Chapters 62-160 and 62-601, F.A.C., and 40 CFR 136, as appropriate.
    a. Monitoring results shall be reported at the intervals specified elsewhere in this permit and shall be reported on a Discharge Monitoring Report (DMR), DEP Form 62-620.910(10).
    b. If the permittee monitors any contaminate more frequently than required by the permit, using Department approved test procedures, the results of this monitoring shall be included in the calculation and reporting of the data submitted in the DMR.
    c. Calculations for all limitations which require averaging of measurements shall use an arithmetic mean unless otherwise specified in this permit.
    d. Any laboratory test required by this permit shall be performed by a laboratory that has been certified by the Department of Health (DOH) under Chapter 64E-1, F.A.C., where such certification is required by Rule 62-160.300(4), F.A.C. The laboratory must be certified for any specific method and analyte combination that is used to comply with this permit. For domestic wastewater facilities, the on-site test procedures specified in Rule 62-160.300(4), F.A.C., shall be performed by a laboratory certified test for those parameters or under the direction of an operator certified under Chapter 62-602, F.A.C.
    e. Fields activities including on-site tests and sample collection, whether performed by a laboratory or a certified operator, must follow the applicable procedures described in DEP-SOP-001/01 (January 2002). Alternate field procedures and laboratory methods may be used where they have been approved according to the requirements of Rules 62-160.220, 62-160.330, and 62-160.600, F.A.C.
    [62-620.610(18), F.A.C.]

19. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule detailed elsewhere in this permit shall be submitted no later than 14 days following each schedule date. *[62-620.610(19), F.A.C.]*

20. The permittee shall report to the Department's Southeast District Office any noncompliance which may endanger health or the environment. Any information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided within five days of

the time the permittee becomes aware of the circumstances. The written submission shall contain: a description of the noncompliance and its cause; the period of noncompliance including exact dates and time, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

a. The following shall be included as information which must be reported within 24 hours under this condition:
   (1) Any unanticipated bypass which causes any reclaimed water or effluent to exceed any permit limitation or results in an unpermitted discharge,
   (2) Any upset which causes any reclaimed water or the effluent to exceed any limitation in the permit,
   (3) Violation of a maximum daily discharge limitation for any of the pollutants specifically listed in the permit for such notice, and
   (4) Any unauthorized discharge to surface or ground waters.
b. Oral reports as required by this subsection shall be provided as follows:
   (1) For unauthorized releases or spills of untreated or treated wastewater reported pursuant to subparagraph a.4 that are in excess of 1,000 gallons per incident, or where information indicates that public health or the environment will be endangered, oral reports shall be provided to the Department by calling the STATE WARNING POINT TOLL FREE NUMBER (800) 320-0519, as soon as practical, but no later than 24 hours from the time the permittee becomes aware of the discharge. The permittee, to the extent known, shall provide the following information to the State Warning Point:
      (a) Name, address, and telephone number of person reporting;
      (b) Name, address, and telephone number of permittee or responsible person for the discharge;
      (c) Date and time of the discharge and status of discharge (ongoing or ceased);
      (d) Characteristics of the wastewater spilled or released (untreated or treated, industrial or domestic wastewater);
      (e) Estimated amount of the discharge;
      (f) Location or address of the discharge;
      (g) Source and cause of the discharge;
      (h) Whether the discharge was contained on-site, and cleanup actions taken to date;
      (i) Description of area affected by the discharge, including name of water body affected, if any; and
      (j) Other persons or agencies contacted.
   (2) Oral reports, not otherwise required to be provided pursuant to subparagraph b(1) above, shall be provided to Department's Southeast District Office within 24 hours from the time the permittee becomes aware of the circumstances.
c. If the oral report has been received within 24 hours, the noncompliance has been corrected, and the noncompliance did not endanger health or the environment, the Department's Southeast District Office shall waive the written report.

[62-620.610(20), F.A.C.]

21. The permittee shall report all instances of noncompliance not reported under Conditions VIII. 18 and 19 of this permit at the time monitoring reports are submitted. This report shall contain the same information required by Condition VIII. 20. of this permit. *[62-620.610(21), F.A.C.]*

22. Bypass Provisions.
   a. Bypass is prohibited, and the Department may take enforcement action against a permittee for bypass, unless the permittee affirmatively demonstrates that:
      (1) Bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and
      (2) There were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime. This condition is not satisfied if adequate back-up equipment should have been installed in the exercise of reasonable engineering judgment to prevent a bypass which occurred during normal periods of equipment downtime or preventative maintenance; and
      (3) The permittee submitted notices as required under Condition VIII.22.b. of this permit.

b. If the permittee knows in advance of the need for a bypass, it shall submit prior notice to the Department, if possible at least 10 days before the date of the bypass. The permittee shall submit notice of an unanticipated bypass within 24 hours of learning about the bypass as required in Condition VIII.20. of this permit. A notice shall include a description of the bypass and its cause; the period of the bypass, including exact dates and times; if the bypass has not been corrected, the anticipated time it is expected to continue; and the steps taken or planned to reduce, eliminate, and prevent recurrence of the bypass.
c. The Department shall approve an anticipated bypass, after considering its adverse effect, if the permittee demonstrates that it will meet the three conditions listed in Condition VIII.22 a. (1) through (3) of this permit.
d. A permittee may allow any bypass to occur which does not cause reclaimed water or effluent limitations to be exceeded if it is for essential maintenance to assure efficient operation. These bypasses are not subject to the provision of Condition VIII.22.a. through c. of this permit.
[62-620.610(22), F.A.C.]

23. Upset Provisions
a. A permittee who wishes to establish the affirmative defense of upset shall demonstrate, through properly signed contemporaneous operating logs, or other relevant evidence that:
(1) An upset occurred and that the permittee can identify the cause(s) of the upset;
(2) The permitted facility was at the time being properly operated;
(3) The permittee submitted notice of the upset as required in Condition VIII.20. of this permit; and
(4) The permittee complied with any remedial measures required under Condition VIII.5. of this permit.
b. In any enforcement proceeding, the permittee seeking to establish the occurrence of an upset has the burden of proof.
c. Before an enforcement proceeding is instituted, no representation made during the Department review of a claim that noncompliance was caused by an upset is final agency action subject to judicial review.
[62-620.610(23), F.A.C.]

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT OF
ENVIRONMENTAL PROTECTION

Mimi Drew

Mimi A. Drew
Director, Division of Water Resource Management
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
(850) 245-8592

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551 , 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME: Florida Power & Light Company
MAILING ADDRESS: 9760 S.W. 344 Street
Florida City, FL 33035

FACILITY: FPL Turkey Point Power Plant
LOCATION: 9760 S.W. 344 Street
Florida City, FL 33035

COUNTY: Dade

PERMIT NUMBER FL0001562

LIMIT: Final
CLASS SIZE: Major
REPORT: Monthly
GROUP: Industrial

MONITORING GROUP NUMBER: I-001
MONITORING GROUP DESC: non-contact once through condenser cooling water

NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: ____________ To ____________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Temperature (F), Water	Sample Measurement										
PARM Code 00011 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	DEG.F		Monthly	Instantaneous
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
	Permit Requirement										

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (YY/MM/DD)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551 , 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME: Florida Power & Light Company
MAILING ADDRESS: 9760 S.W. 344 Street
Florida City, FL 33035

FACILITY: FPL Turkey Point Power Plant
LOCATION: 9760 S.W. 344 Street
Florida City, FL 33035

COUNTY: Dade

PERMIT NUMBER FL0001562

LIMIT: Final REPORT: Quarterly
CLASS SIZE: Major GROUP: Industrial

MONITORING GROUP NUMBER: I-001
MONITORING GROUP DESC: non-contact once through condenser cooling water

NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: ____________ To ____________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Solids, Total Suspended	Sample Measurement										
PARM Code 00530 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	MG/L		Quarterly	Grab
pH	Sample Measurement										
PARM Code 00400 P Mon. Site No. OUI-1	Permit Requirement					Report (Day.Min.)	Report (Day.Max.)	SU		Quarterly	Grab
Salinity	Sample Measurement										
PARM Code 00480 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	PPT		Quarterly	Grab
Specific Conductance	Sample Measurement										
PARM Code 00095 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	UMHO/ CM		Quarterly	Grab
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
	Permit Requirement										

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MAILING ADDRESS: 9760 S.W. 344 Street
Florida City, FL 33035

FACILITY: FPL Turkey Point Power Plant
LOCATION: 9760 S.W. 344 Street
Florida City, FL 33035

COUNTY: Dade

PERMIT NUMBER FL0001562

LIMIT: Final
CLASS SIZE: Major
REPORT: Semiannual
GROUP: Industrial

MONITORING GROUP NUMBER: I-001
MONITORING GROUP DESC: non-contact once through condenser cooling water

NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: ____________ To ____________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Copper, Total Recoverable	Sample Measurement										
PARM Code 01119 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	UG/L		Semiannually	Grab
Iron, Total Recoverable	Sample Measurement										
PARM Code 00980 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	MG/L		Semiannually	Grab
Zinc, Total Recoverable	Sample Measurement										
PARM Code 01094 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	UG/L		Semiannually	Grab
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
	Permit Requirement										

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DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

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PERMITTEE NAME: Florida Power & Light Company
MAILING ADDRESS: 9760 S.W. 344 Street
Florida City, FL 33035

FACILITY: FPL Turkey Point Power Plant
LOCATION: 9760 S.W. 344 Street
Florida City, FL 33035

COUNTY: Dade

PERMIT NUMBER FL0001562

LIMIT: Final
CLASS SIZE: Major
REPORT: Monthly
GROUP: Industrial

MONITORING GROUP NUMBER: I-002
MONITORING GROUP DESC: low volume wastewater (LVW) and equipment area stormwater discharged

NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: ____________ To ____________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
pH	Sample Measurement										
PARM Code 00400 P Mon. Site No. OUI-002	Permit Requirement					Report (Day.Min.)	Report (Day.Max.)	SU		Monthly	Grab
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
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MAILING ADDRESS: 9760 S.W. 344 Street
Florida City, FL 33035

FACILITY: FPL Turkey Point Power Plant
LOCATION: 9760 S.W. 344 Street
Florida City, FL 33035

COUNTY: Dade

PERMIT NUMBER FL0001562

LIMIT: Final
CLASS SIZE: Major

REPORT: Quarterly
GROUP: Industrial

MONITORING GROUP NUMBER: I-002
MONITORING GROUP DESC: low volume wastewater (LVW) and equipment area stormwater discharged

NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: ____________ To ____________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Specific Conductance	Sample Measurement										
PARM Code 00095 P Mon. Site No. OUI-002	Permit Requirement						Report (Day.Max.)	UMHO/CM		Quarterly	Grab
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
	Permit Requirement										
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Florida City, FL 33035

FACILITY: FPL Turkey Point Power Plant
LOCATION: 9760 S.W. 344 Street
Florida City, FL 33035

COUNTY: Dade

PERMIT NUMBER FL0001562

LIMIT: Final
CLASS SIZE: Major
REPORT: Semiannual
GROUP: Industrial

MONITORING GROUP NUMBER: I-002
MONITORING GROUP DESC: low volume wastewater (LVW) and equipment area stormwater discharged

NO DESCHARGE FROM SITE: ☐
MONITORING PERIOD From: ____________ To ____________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Solids, Total Suspended	Sample Measurement										
PARM Code 00530 P Mon. Site No. OUI-002	Permit Requirement						Report (Day.Max.)	MG/L		Semiannually	Grab
Lead, Total Recoverable	Sample Measurement										
PARM Code 01114 P Mon. Site No. OUI-002	Permit Requirement						Report (Day.Max.)	UG/L		Semiannually	Grab
Oil and Grease	Sample Measurement										
PARM Code 00556 P Mon. Site No. OUI-002	Permit Requirement						Report (Day.Max.)	MG/L		Semiannually	Grab
Copper, Total Recoverable	Sample Measurement										
PARM Code 01119 P Mon. Site No. OUI-002	Permit Requirement						Report (Day.Max.)	UG/L		Semiannually	Grab
Zinc, Total Recoverable	Sample Measurement										
PARM Code 01094 P Mon. Site No. OUI-002	Permit Requirement						Report (Day.Max.)	UG/L		Semiannually	Grab
	Sample Measurement										
	Permit Requirement										

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (YY/MM/DD)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

INSTRUCTIONS FOR COMPLETING THE WASTEWATER DISCHARGE MONITORING REPORT

Read these instructions as well as the SUPPLEMENTAL INSTRUCTIONS FOR COMPLETING THE WASTEWATER DISCHARGE MONITORING REPORT before completing the DMR. Hard copies and/or electronic copies of the required parts of the DMR were provided with the permit. All required information shall be completed in full and typed or printed in ink. A signed, original DMR shall be mailed to the address printed on the DMR by the 28th of the month following the monitoring period. The DMR shall not be submitted before the end of the monitoring period.

The DMR consists of three parts--A, B, and D--all of which may or may not be applicable to every facility. Facilities may have one or more Part A's for reporting effluent or reclaimed water data. All domestic wastewater facilities will have a Part B for reporting daily sample results. Part D is used for reporting ground water monitoring well data.
When results are not available, the following codes should be used on parts A and D of the DMR and an explanation provided where appropriate. Note: Codes used on Part B for raw data are different.

CODE	DESCRIPTION/INSTRUCTIONS
ANC	Analysis not conducted.
DRY	Dry Well
FLD	Flood disaster.
IFS	Insufficient flow for sampling.
LS	Lost sample.
MNR	Monitoring not required this period.

CODE	DESCRIPTION/INSTRUCTIONS
NOD	No discharge from/to site.
OPS	Operations were shutdown so no sample could be taken.
OTH	Other. Please enter an explanation of why monitoring data were not available.
SEF	Sampling equipment failure.

When reporting analytical results that fall below a laboratory's reported method detection limits or practical quantification limits, the following instructions should be used:

1. Results greater than or equal to the PQL shall be reported as the measured quantity.
2. Results less than the PQL and greater than or equal to the MDL shall be reported as the laboratory's MDL value. These values shall be deemed equal to the MDL when necessary to calculate an average for that parameter and when determining compliance with permit limits.
3. Results less than the MDL shall be reported by entering a less than sign ("<") followed by the laboratory's MDL value, e.g. < 0.001. A value of one-half the MDL or one-half the effluent limit, whichever is lower, shall be used for that sample when necessary to calculate an average for that parameter. Values less than the MDL are considered to demonstrate compliance with an effluent limitation.

PART A -DISCHARGE MONITORING REPORT (DMR)

Part A of the DMR is comprised of one or more sections, each having its own header information. Facility information is preprinted in the header as well as the monitoring group number, whether the limits and monitoring requirements are interim or final, and the required submittal frequency (e.g. monthly, annually, quarterly, etc.). Submit Part A based on the required reporting frequency in the header and the instructions shown in the permit. The following should be completed by the permittee or authorized representative:

No Discharge From Site: Check this box if no discharge occurs and, as a result, there are no data or codes to be entered for all of the parameters on the DMR for the entire monitoring group number; however, if the monitoring group includes other monitoring locations (e.g., influent sampling), the "NOD" code should be used to individually denote those parameters for which there was no discharge.
Monitoring Period: Enter the month, day, and year for the first and last day of the monitoring period (i.e. the month, the quarter, the year, etc.) during which the data on this report were collected and analyzed.
Sample Measurement: Before filling in sample measurements in the table, check to see that the data collected correspond to the limit indicated on the DMR (i.e. interim or final) and that the data correspond to the monitoring group number in the header. Enter the data or calculated results for each parameter on this row in the non-shaded area above the limit. Be sure the result being entered corresponds to the appropriate statistical base code (e.g. annual average, monthly average, single sample maximum, etc.) and units.
No. Ex.: Enter the number of sample measurements during the monitoring period that exceeded the permit limit for each parameter in the non-shaded area. If none, enter zero.
Frequency of Analysis: The shaded areas in this column contain the minimum number of times the measurement is required to be made according to the permit. Enter the actual number of times the measurement was made in the space above the shaded area.
Sample Type: The shaded areas in this column contain the type of sample (e.g. grab, composite, continuous) required by the permit. Enter the actual sample type that was taken in the space above the shaded area.
Signature: This report must be signed in accordance with Rule 62-620.305, F.A.C. Type or print the name and title of the signing official. Include the telephone number where the official may be reached in the event there are questions concerning this report. Enter the date when the report is signed.
Comment and Explanation of Any Violations: Use this area to explain any exceedances, any upset or by-pass events, or other items which require explanation. If more space is needed, reference all attachments in this area.

PART B - DAILY SAMPLE RESULTS

Monitoring Period: Enter the month, day, and year for the first and last day of the monitoring period (i.e. the month, the quarter, the year, etc.) during which the data on this report were collected and analyzed.
Daily Monitoring Results: Transfer all analytical data from your facility's laboratory or a contract laboratory's data sheets for all day(s) that samples were collected. Record the data in the units indicated. Table 1 in Chapter 62-160, F.A.C., contains a complete list of all the data qualifier codes that your laboratory may use when reporting analytical results. However, when transferring numerical results onto Part B of the DMR, only the following data qualifier codes should be used and an explanation provided where appropriate.

CODE	DESCRIPTION/INSTRUCTIONS
<	The compound was analyzed for but not detected.
A	Value reported is the mean (average) of two or more determinations.
J	Estimated value, value not accurate.
Q	Sample held beyond the actual holding time.
Y	Laboratory analysis was from an unpreserved or improperly preserved sample.

Add the results to get the Total and divide by the number of days in the month to get the Monthly Average.
Plant Staffing: List the name, certificate number, and class of all state certified operators operating the facility during the monitoring period. Use additional sheets as necessary.

PART D - GROUND WATER MONITORING REPORT

Monitoring Period: Enter the month, day, and year for the first and last day of the monitoring period (i.e. the month, the quarter, the year, etc.) during which the data on this report were collected and analyzed.
Date Sample Obtained: Enter the date the sample was taken. Also, check whether or not the well was purged before sampling.
Time Sample Obtained: Enter the time the sample was taken.
Sample Measurement: Record the results of the analysis. If the result was below the minimum detection limit, indicate that.
Detection Limits: Record the detection limits of the analytical methods used.
Analysis Method: Indicate the analytical method used. Record the method number from Chapter 62-160 or Chapter 62-601, F.A.C., or from other sources.
Sampling Equipment Used: Indicate the procedure used to collect the sample (e.g. airlift, bucket/bailer, centrifugal pump, etc.)
Samples Filtered: Indicate whether the sample obtained was filtered by laboratory (L), filtered in field (F), or unfiltered (N).
Signature: This report must be signed in accordance with Rule 62-620.305, F.A.C. Type or print the name and title of the signing official. Include the telephone number where the official may be reached in the event there are questions concerning this report. Enter the date when the report is signed.
Comments and Explanation: Use this space to make any comments on or explanations of results that are unexpected. If more space is needed, reference all attachments in this area.

SPECIAL INSTRUCTIONS FOR LIMITED WET WEATHER DISCHARGES

Flow (Limited Wet Weather Discharge): Enter the measured average flow rate during the period of discharge or divide gallons discharged by duration of discharge (converted into days). Record in million gallons per day (MGD).
Flow (Upstream): Enter the average flow rate in the receiving stream upstream from the point of discharge for the period of discharge. The average flow rate can be calculated based on two measurements; one made at the start and one made at the end of the discharge period. Measurements are to be made at the upstream gauging station described in the permit.
Actual Stream Dilution Ratio: To calculate the Actual Stream Dilution Ratio, divide the average upstream flow rate by the average discharge flow rate. Enter the Actual Stream Dilution Ratio accurate to the nearest 0.1.
No. of Days the SDF > Stream Dilution Ratio: For each day of discharge, compare the minimum Stream Dilution Factor (SDF) from the permit to the calculated Stream Dilution Ratio. On Part B of the DMR, enter an asterisk (*) if the SDF is greater than the Stream Dilution Ratio on any day of discharge. On Part A of the DMR, add up the days with an "*" and record the total number of days the Stream Dilution Factor was greater than the Stream Dilution Ratio.
$CBOD_5$: Enter the average $CBOD_5$ of the reclaimed water discharged during the period shown in duration of discharge.
TKN: Enter the average TKN of the reclaimed water discharged during the period shown in duration of discharge.
Actual Rainfall: Enter the actual rainfall for each day on Part B. Enter the actual cumulative rainfall to date for this calendar year and the actual total monthly rainfall on Part A. The cumulative rainfall to date for this calendar year is the total amount of rain, in inches, that has been recorded since January 1 of the current year through the month for which this DMR contains data.
Rainfall During Average Rainfall Year: On Part A, enter the total monthly rainfall during the average rainfall year and the cumulative rainfall for the average rainfall year. The cumulative rainfall for the average rainfall year is the amount of rain, in inches, which fell during the average rainfall year from January through the month for which this DMR contains data.
No. of Days LWWD Activated During Calendar Year: Enter the cumulative number of days that the limited wet weather discharge was activated since January 1 of the current year.
Reason for Discharge: Attach to the DMR a brief explanation of the factors contributing to the need to activate the limited wet weather discharge.

FLORIDA DEPARTMENT OF Environmental Protection

Tallahassee Office
2600 Blair Stone Road, M.S. 3545
Tallahassee, Florida 32399-2400

Ron DeSantis
Governor

Jeanette Nuñez
Lt. Governor

Noah Valenstein
Secretary

April 13, 2020

SENT BY EMAIL TO:
(Brian.Stamp@fpl.com)

In the Matter of an
Application for Permit by:

Florida Power & Light Company
Mr. Brian Stamp
Plant Turkey Nuclear General Manager
9760 SW 344 Street
Florida City, Florida 33035

Miami-Dade County
Turkey Point Power Plant
NPDES Permit No. FL0001562
PA File No. FL0001562-012-IW1N

INTENT TO ISSUE

The Department of Environmental Protection gives notice of its intent to issue a permit (copy of conditions attached) for the proposed project as detailed in the application specified above, for the reasons stated below.

The applicant, Florida Power & Light Company, applied on October 22, 2009, to the Department of Environmental Protection for a permit to operate wastewater treatment and effluent disposal facilities at Turkey Point Power Plant. The facility is located at 9760 SW 344 Street, Florida City, Florida 33035 in Miami-Dade County, Florida.

The Department has permitting jurisdiction under Chapter 403, Florida Statutes (F.S.), and applicable rules of the Florida Administrative Code (F.A.C.). The project is not exempt from permitting procedures. The Department has determined that a wastewater permit is required for the proposed work.

Based upon the application and supplemental information, the Department has determined that the applicant has provided reasonable assurance that the above described wastewater project complies with the applicable provisions of Chapter 403, F.S., and Title 62 of the F.A.C.

Under Section 403.815, F.S., and Rule 62-110.106, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Notice of Intent to Issue Permit. The notice must be published one time only within 30 days of receipt of this intent to issue in the legal ad section of a newspaper of general circulation in the area affected. For the purpose of this rule, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. Where there is more than one newspaper of general circulation in the county, the newspaper used should be one with significant circulation in the area that may be affected by the permit. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant must provide proof of publication to the Department's Wastewater Management Program, 2600 Blair Stone Road, M.S. 3545, Tallahassee, Florida 32399-2400 within two weeks of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit under Rule 62-110.106(11), F.A.C.

NOTICE OF RIGHTS

The Department will issue the permit unless a petition for an administrative hearing is timely filed under Sections 120.569 and 120.57, F.S., before the deadline for filing a petition. On the filing of a timely and sufficient petition, this action will not be final and effective until further order of the Department. Because the administrative hearing process is designed to formulate final agency action, the hearing process may result in a modification of the agency action or even denial of the application.

<u>Petition for Administrative Hearing</u>
A person whose substantial interests are affected by the Department's action may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, F.S. Pursuant to Rules 28-106.201 and 28-106.301, F.A.C., a petition for an administrative hearing must contain the following information:

(a) The name and address of each agency affected and each agency's file or identification number, if known;
(b) The name, address, any e-mail address, any facsimile number, and telephone number of the petitioner, if the petitioner is not represented by an attorney or a qualified representative; the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination;
(c) A statement of when and how the petitioner received notice of the agency decision;
(d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate;
(e) A concise statement of the ultimate facts alleged, including the specific facts that the petitioner contends warrant reversal or modification of the agency's proposed action;
(f) A statement of the specific rules or statutes that the petitioner contends require reversal or modification of the agency's proposed action, including an explanation of how the alleged facts relate to the specific rules or statutes; and
(g) A statement of the relief sought by the petitioner, stating precisely the action that the petitioner wishes the agency to take with respect to the agency's proposed action.

The petition must be filed (received by the Clerk) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000, or via electronic correspondence at Agency_Clerk@dep.state.fl.us. Also, a copy of the petition shall be mailed to the applicant at the address indicated above at the time of filing.

<u>Time Period for Filing a Petition</u>
In accordance with Rule 62-110.106(3), F.A.C., petitions for an administrative hearing by the applicant and persons entitled to written notice under Section 120.60(3), F.S., must be filed within 14 days of receipt of this written notice. Petitions filed by any persons other than the applicant, and other than those entitled to written notice under Section 120.60(3), F.S., must be filed within 14 days of publication of

the notice or within 14 days of receipt of the written notice, whichever occurs first. The failure to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention (in a proceeding initiated by another party) will be only at the discretion of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

Extension of Time

Under Rule 62-110.106(4), F.A.C., a person whose substantial interests are affected by the Department's action may also request an extension of time to file a petition for an administrative hearing. The Department may, for good cause shown, grant the request for an extension of time. Requests for extension of time must be filed with the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000, or via electronic correspondence at Agency_Clerk@dep.state.fl.us, before the deadline for filing a petition for an administrative hearing. A timely request for extension of time shall toll the running of the time period for filing a petition until the request is acted upon.

Mediation

Mediation is not available in this proceeding.

EXECUTION AND CLERKING

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Benjamin M Melnick

Benjamin M. Melnick
Director
Division of Water Resource Management

Attachment(s):

1. Proposed Permit No. FL0001562
2. Notice of Intent to Issue Permit for newspaper publication
3. Discharge Monitoring Report
4. Fact Sheet

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that this document and all attachments were sent on the filing date below to the following listed persons:

Danielle Hall, Environmental Services Manager, FPL (danielle.hall@fpl.com)
EPA Region 4 (r4npdespermits@epa.gov)
Karrie-Jo Shell, Power Plant NPDES Permits, EPA Region 4 (shell.karrie-Jo@epa.gov)
Lee Hefty, Director, Division of Regulatory and Economic Resources, Miami-Dade DERM (heftyl@miamidade.gov)
Terrie Bates, Director, Water Resources Division, SFWMD (tbates@sfwmd.gov)
Audrey M. Edmonson, Chairman, Board of Miami-Dade County Commissioners (district3@miamidade.gov)
FWC, Conservation Planning Services (fwcconservationplanningservices@myfwc.com)
Charles Calleson, U.S. Fish and Wildlife Service (charles_calleson@fws.gov)
Nick Farmer, Ph.D., National Marine Fisheries Service (nick.farmer@noaa.gov)
Joe Heublein, National Marine Fisheries Service (joe.heublein@noaa.gov)
Penelope Del Bene, Superintendent, Biscayne National Park, National Park Service (penelope_delbene@nps.gov)
Florida Department of Economic Opportunity, State Land Planning Agency (dcppermits@deo.myflorida.com)
Florida Department of State, Bureau of Historic Preservation (compliancepermits@dos.state.fl.us)
U.S. Army Corps of Engineers (james.j.mcadams@usace.army.mil)
Jason Andreotta, Director, Southeast District, FDEP (jason.andreotta@floridadep.gov)
Kent Edwards, Program Administrator, Southeast District, FDEP (kent.edwards@floridadep.gov)
Cindy Mulkey, Program Administrator, Siting Coordination Office, FDEP (cindy.mulkey@floridadep.gov)

FILING AND ACKNOWLEDGMENT

FILED, on this date, pursuant to Section 120.52, F. S., with the designated Department Clerk, receipt of which is hereby acknowledged.

Shirley Shields | April 13, 2020
Clerk | **Date**

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF INTENT TO ISSUE PERMIT

The Department of Environmental Protection gives notice of its intent to issue a permit to Florida Power & Light Company for the Turkey Point Power Plant. This permit authorizes the permittee to operate wastewater treatment and effluent disposal facilities at the Turkey Point Power Plant. The facility is located at 9760 SW 344 Street, Florida City, Florida 33035 in Miami-Dade County, Florida. The Department has assigned permit file number FL0001562-012-IW1N to the proposed project.

The intent to issue and application file are available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at the Department's Wastewater Management Program, 2600 Blair Stone Road, M.S. 3545, Tallahassee, Florida 32399-2400, at phone number (850)245-8589.

NOTICE OF RIGHTS

The Department will issue the permit unless a petition for an administrative hearing is timely filed under Sections 120.569 and 120.57, F.S., before the deadline for filing a petition. On the filing of a timely and sufficient petition, this action will not be final and effective until further order of the Department. Because the administrative hearing process is designed to formulate final agency action, the hearing process may result in a modification of the agency action or even denial of the application.

<u>Petition for Administrative Hearing</u>
A person whose substantial interests are affected by the Department's action may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, F.S. Pursuant to Rules 28-106.201 and 28-106.301, F.A.C., a petition for an administrative hearing must contain the following information:

(a) The name and address of each agency affected and each agency's file or identification number, if known;
(b) The name, address, any e-mail address, any facsimile number, and telephone number of the petitioner, if the petitioner is not represented by an attorney or a qualified representative; the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination;
(c) A statement of when and how the petitioner received notice of the Department's agency decision;
(d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate;
(e) A concise statement of the ultimate facts alleged, including the specific facts that the petitioner contends warrant reversal or modification of the agency's proposed action;

(f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action, including an explanation of how the alleged facts relate to the specific rules or statutes; and
(g) A statement of the relief sought by the petitioner, stating precisely the action that the petitioner wishes the agency to take with respect to the agency's proposed action.

The petition must be filed (received by the Clerk) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000, or via electronic correspondence at Agency_Clerk@dep.state.fl.us. Also, a copy of the petition shall be mailed to the applicant at the address indicated above at the time of filing.

Time Period for Filing a Petition

Petitions filed by any persons other than the applicant, and other than those entitled to written notice under Section 120.60(3), F.S., must be filed within 14 days of publication of the notice or within 14 days of receipt of the written notice, whichever occurs first. The failure to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention (in a proceeding initiated by another party) will be only at the discretion of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

Extension of Time

Under Rule 62-110.106(4), F.A.C., a person whose substantial interests are affected by the Department's action may also request an extension of time to file a petition for an administrative hearing. The Department may, for good cause shown, grant the request for an extension of time. Requests for extension of time must be filed with the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000, or via electronic correspondence at Agency_Clerk@dep.state.fl.us, before the deadline for filing a petition for an administrative hearing. A timely request for extension of time shall toll the running of the time period for filing a petition until the request is acted upon.

Mediation

Mediation is not available in this proceeding.

STATE OF FLORIDA
INDUSTRIAL WASTEWATER FACILITY PERMIT

PERMITTEE: Florida Power & Light Company (FPL) 9760 S.W. 344 Street Florida City, Florida 33035	**PERMIT NUMBER:** FL0001562 (Major) **FILE NUMBER:** FL0001562-012-IW1N **ISSUANCE DATE:** **PROPOSED** **EXPIRATION DATE:** **PROPOSED**

RESPONSIBLE OFFICIAL:

Brian Stamp
Point Turkey Nuclear (PTN) General Manager

FACILITY:

FPL Turkey Point Power Plant
9760 SW 344 Street
Florida City, Florida 33035
Miami-Dade County

Latitude: 25° 26' 09" N Longitude: 80° 19' 51" W

This permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.) and applicable rules of the Florida Administrative Code (F.A.C.), and authorizes discharges explicitly expressed in this permit. The above-named permittee is hereby authorized to operate the facilities shown on the application and other documents attached hereto or on file with the Department and made a part hereof and specifically described as follows:

FACILITY DESCRIPTION:

Turkey Point (Figure 1) is located on approximately 11,000 acres in unincorporated southeast Miami-Dade County about 25 miles south of Miami and about nine miles east of Florida City and Homestead. Biscayne National Park lies adjacent to northeastern and eastern portions of the facility. The Biscayne Bay Aquatic Preserve is north northeast and southeast of the facility. Everglades National Park is to the south and west (Figure 2). The boundaries of the facility governed by this permit are provided in Figure 3. A map showing the boundaries of the Turkey Point facility, Biscayne National Park, and Biscayne Bay Aquatic Preserve is attached to this permit.

Several canals are in close proximity to the facility. West of the facility are the South Florida Water Management District (SFWMD) L-31E Canal, the historic C-106 Canal (Model Lands North Canal), and the historic C-107 Canal (Model Lands South Canal). Southeast of the facility is the Card Sound Canal and southwest and south is the SFWMD S-20 Discharge Canal. The remnant canals at Turtle Point and the Barge Basin are located east northeast and northeast of the facility, respectively.

The facility consists of three electrical generating units: two nuclear units (Units 3 and 4) and one natural gas-fired combined cycle unit (Unit 5). Units 3, 4, and 5 began commercial operation in 1972, 1973, and 2007, respectively. Units 3 and 4 each have a nominal capacity of 815 Megawatts (MW) and Unit 5 has a nominal capacity of 1209 MW. Units 3, 4 and 5 are also regulated under the Florida Electrical Power Plant Siting Act (License No. PA03-045).

FPL owns and operates a cooling canal system (CCS) at the facility, which provides wastewater treatment and effluent disposal for Units 3, 4, and 5. The CCS provides a heat removal function for the cooling water from Units 3 and 4. The heated water generated by operation of Units 3 and 4 is discharged to the recirculating CCS and returned to Units 3 and 4. The temperature of the water returned to Units 3 and 4 is regulated by the U.S. Nuclear Regulatory Commission under the Atomic Energy Act. Groundwater withdrawals from the Floridan aquifer is the source of cooling water for Unit 5, and is authorized under License No. PA03-045.

WASTEWATER TREATMENT:

Stormwater and wastewater associated with power generation and ancillary activities are released to the CCS, which discharges to groundwater beneath the system.

Stormwater runoff associated with loading and unloading operations, outdoor storage, outdoor process activities, and ancillary maintenance activities is directed toward and released into the CCS. The quantities of stormwater generated from these activities are dependent on many variables, including the length and intensity of the storm event. Wastewater generated by Units 3 and 4 includes intermittent chemical volume control system including wet lay-up, feedwater condensate including wet lay-up, on-line chemical analyzer, steam generator blowdown, condensate polisher backwash, reverse osmosis reject, circulating water pumps seal water, alternate flow from the circulating water pump seal water tank, non-equipment area stormwater, maintenance/wash through equipment area/closed cooling water system maintenance, plant intake screen wash, and non-contact once-through condenser cooling water (OTCW).

Wastewater generated by Unit 5 includes cooling water, emergency generator backup cooling water, non-equipment area stormwater, equipment area stormwater and plant drains following oil/water separation, and wastewater sump discharge which includes heat recovery steam generator blowdown, wastewater treatment system blowdown, and cooling water treatment reject.

REUSE OR DISPOSAL:

Groundwater Discharge: The CCS is not lined, and is authorized to discharge to Class G-III groundwater. Groundwater monitoring requirements for this facility are in accordance with Section I of this permit. The discharge shall meet the Class G-III groundwater standards of Rule 62-520.430, F.A.C. In addition, the discharge shall not impair the reasonable and beneficial use of adjacent waters beyond the facility boundary in Figure 3 in accordance with Rule 62-520.400(1)(f), F.A.C. The 1972 Environmental Impact Statement acknowledges that some seepage of water from the CCS may reach surface waters. To the extent that such seepage occurs, it shall not cause or contribute to a violation of the surface water quality standards or criteria in Chapter 62-302, F.A.C. This authorization to discharge shall not be deemed to pre-empt or prohibit the regulatory implementation, adoption, continuation or enforcement of standards or criteria established by a local government through a local pollution control program.

Surface Water Discharges: This permit does not authorize surface water discharges from the CCS through a point source to surface waters of the State.

Internal Outfall I-001: An existing permitted outfall that discharges plant process wastewater to the facility's on-site CCS.

Groundwater Monitoring Group G-001: A new permitted series that monitors groundwater.

Surface Water Monitoring Group D-01A: A new permitted series of surface water monitoring sites in Biscayne Bay, L-31E canal, S-20 canal and Card Sound canal that monitors surface waters.

Porewater Monitoring Group D-02A: A new permitted series of porewater (free water present in sediments) monitoring sites in coastal marine wetlands north, east, and south of the facility's onsite CCS.

Stormwater Discharges: This permit authorizes stormwater to be released to the facility's on-site CCS. Stormwater will intermittently include wash-down water consisting of potable water with no additives.

IN ACCORDANCE WITH: The limitations, monitoring requirements and other conditions as set forth in Part I through Part IX on pages 2 through 44 of this permit.

I. GROUNDWATER MONITORING REQUIREMENTS

1. The permittee's discharges to groundwater shall not cause a violation of the groundwater quality standards or criteria specified in Rules 62-520.400, 62-520.420 and 62-520.430, F.A.C., in adjacent groundwaters.[1] Compliance with this requirement shall be achieved in accordance with the Compliance Schedule in Section VI.8 - 10 of this permit as supplemented by the groundwater well monitoring in this Section.

[1] Consent Order OGC File Number 16-0241, paragraphs 19 and 20 stipulate remedial actions and timelines for achieving compliance with groundwater minimum criteria of Rule 62-520.400, F.A.C.

2. The permittee's discharges to groundwater shall not impair the designated use of contiguous surface waters.[2] *[62-520.310(2)]*

3. During the period of operation authorized by this permit, the permittee shall sample groundwater from the Biscayne aquifer from the following monitoring wells, designated as **Groundwater Monitoring Group G-001,** as described below:

Monitoring Well ID	Description of Monitoring Location	Latitude			Longitude		
		o	'	"	o	'	"
TPGW-1S	West of Canal L-31E, west of northwest corner of the CCS (shallow)	25	26	4.7	80	21	15.8
TPGW-1M	West of Canal L-31E, west of northwest corner of the CCS (intermediate)	25	26	4.7	80	21	15.8
TPGW-1D	West of Canal L-31E, west of northwest corner of the CCS (deep)	25	26	4.7	80	21	15.8
TPGW-2S	West of the south-central portion of the CCS (shallow)	25	22	54.2	80	22	11.4
TPGW2M	West of the south-central portion of the CCS (intermediate)	25	22	54.2	80	22	11.4
TPGW-2D	West of the south-central portion of the CCS (deep)	25	22	54.2	80	22	11.4
TPGW-3S	South of the CCS (shallow)	25	20	42.1	80	20	51.9
TPGW-3M	South of the CCS (intermediate)	25	20	42.1	80	20	51.9
TPGW-3D	South of the CCS (deep)	25	20	42.1	80	20	51.9
TPGW-4S	Southwest Model Lands, at Tallahassee Road (shallow)	25	22	12.0	80	24	44.1
TPGW-4M	Southwest Model Lands, at Tallahassee Road (intermediate)	25	22	12.0	80	24	44.1
TPGW-4D	Southwest Model Lands, at Tallahassee Road (deep)	25	22	12.0	80	24	44.1
TPGW-5S	Northwest Model Lands – east of Tallahassee Road (shallow)	25	25	23.9	80	24	13.3
TPGW-5M	Northwest Model Lands – east of Tallahassee Road (intermediate)	25	25	23.9	80	24	13.3
TPGW-5D	Northwest Model Lands – east of Tallahassee Road (deep)	25	25	23.9	80	24	13.3
TPGW-6S	Northwest of the CCS, east of Homestead – Miami Speedway (shallow)	25	27	20.3	80	23	13.0
TPGW-6M	Northwest of the CCS, east of Homestead – Miami Speedway (intermediate)	25	27	20.3	80	23	13.0
TPGW-6D	Northwest of the CCS, east of Homestead – Miami Speedway (deep)	25	27	20.3	80	23	13.0
TPGW-7S	Northwest Model Lands (shallow)	25	26	02.5	80	25	40.7
TPGW-7M	Northwest Model Lands (intermediate)	25	26	02.5	80	25	40.7
TPGW-7D	Northwest Model Lands (deep)	25	26	02.5	80	25	40.7
TPGW-8S	West central Model Lands (shallow)	25	24	36.4	80	27	08.7
TPGW-8M	West central Model Lands (intermediate)	25	24	36.4	80	27	08.7
TPGW-8D	West central Model Lands (deep)	25	24	36.4	80	27	08.7
TPGW-9S	West of Card Sound Canal Road, southwest of CCS (shallow)	25	22	28.6	80	28	41.9
TPGW-9M	West of Card Sound Canal Road, southwest of CCS (intermediate)	25	22	28.6	80	28	41.9
TPGW-9D	West of Card Sound Canal Road, southwest of CCS (deep)	25	22	28.6	80	28	41.9
TPGW-10S	Biscayne Bay, channel entrance to Barge Basin (shallow)	25	26	27.4	80	19	29.0
TPGW-10M	Biscayne Bay, channel entrance to Barge Basin (intermediate)	25	26	27.4	80	19	29.0
TPGW-10D	Biscayne Bay, channel entrance to Barge Basin (deep)	25	26	27.4	80	19	29.0
TPGW-11S	Biscayne Bay, east of the CCS (shallow)	25	23	49.4	80	18	15.0
TPGW-11M	Biscayne Bay, east of the CCS (intermediate)	25	23	49.4	80	18	15.0
TPGW-11D	Biscayne Bay, east of the CCS (deep)	25	23	49.4	80	18	15.0
TPGW-12S	North of the CCS (shallow)	25	26	55.4	80	20	22.9
TPGW-12M	North of the CCS (intermediate)	25	26	55.4	80	20	22.9
TPGW-12D	North of the CCS (deep)	25	26	55.4	80	20	22.9
TPGW-13S	In the central portion of the CCS (shallow)	25	23	39.0	80	21	07.1
TPGW-13M	In the central portion of the CCS (intermediate)	25	23	39.0	80	21	07.1
TPGW-13D	In the central portion of the CCS (deep)	25	23	39.0	80	21	07.1
TPGW-14S	Biscayne Bay, southeast of the CCS (shallow)	25	21	15.5	80	19	34.5
TPGW-14M	Biscayne Bay, southeast of the CCS (intermediate)	25	21	15.5	80	19	34.5
TPGW-14D	Biscayne Bay, southeast of the CCS (deep)	25	21	15.5	80	19	34.5
TPGW-15S	Northwest corner of CCS (shallow)	25	25	56.9	80	21	2.5

[2] Consent Order OGC File Number 16-0241, paragraphs 19 and 21 stipulate actions and timelines to prevent violations subsection 62-520.310(2), F.A.C.

Monitoring Well ID	Description of Monitoring Location	Latitude			Longitude		
		°	'	"	°	'	"
TPGW-15M	Northwest corner of CCS (intermediate)	25	25	56.9	80	21	2.5
TPGW-15D	Northwest corner of CCS (deep)	25	25	56.9	80	21	2.5
TPGW-16S	East of the south-central portion of the CCS (shallow)	25	22	37.7	80	19	53.8
TPGW-16M	East of the south-central portion of the CCS (intermediate)	25	22	37.7	80	19	53.8
TPGW-16D	East of the south-central portion of the CCS (deep)	25	22	37.7	80	19	53.8
TPGW-17S	East of the L-31E canal, adjacent to S-20 structure (shallow)	25	22	1.4	80	22	32.2
TPGW-17M	East of the L-31E canal, adjacent to S-20 structure (intermediate)	25	22	1.4	80	22	32.2
TPGW-17D	East of the L-31E canal, adjacent to S-20 structure (deep)	25	22	1.4	80	22	32.2
TPGW-18S	Model Lands, west of L-3 (shallow)	25	25	12.5	80	22	17.8
TPGW-18M	Model Lands, west of L-3 (intermediate)	25	25	12.5	80	22	17.8
TPGW-18D	Model Lands, west of L-3 (deep)	25	25	12.5	80	22	17.8
TPGW-19S	Model Lands, north of Florida City Canal (shallow)	25	26	54.2	80	21	31.33
TPGW-19M	Model Lands, north of Florida City Canal (intermediate)	25	26	54.2	80	21	31.33
TPGW-19D	Model Lands, north of Florida City Canal (deep)	25	26	54.2	80	21	31.33
TPGW-20D	Adjacent to City of Homestead baseball complex	25	27	9.99	80	26	0.5
TPGW-21S	Converted USGS well G-3164 (shallow)	25	25	20.2	80	26	10
TPGW-21M	Converted USGS well G-3164 (intermediate)	25	25	20.2	80	26	10
TPGW-21D	Converted USGS well G-3164 (deep)	25	25	20.2	80	19	10
L-3	East of the L-31E canal, north-central portion of the CCS (Not Automated). This well is an open-hole well, monitored at approximately 18 feet and 58 feet below land surface.	25	25	09.7	80	21	28.7
L-5	East of the L-31E canal, south-central portion of the CCS (Not Automated). This well is an open-hole well, monitored at approximately 18 feet and 58 feet below land surface.	25	23	20.9	80	22	07.3
G-28	Tallahassee Rd, south of Model Lands basin (Not Automated). This well is an open-hole well, monitored at approximately 18 feet and 58 feet below land surface.	25	23	25.5	80	24	43.6
G-21	Tallahassee Rd, north of Model Lands basin (Not Automated). This well is an open-hole well, monitored at approximately 18 feet and 58 feet below land surface.	25	25	34.8	80	24	42.9

[62-520.600]

4. The following parameters shall be analyzed for monitoring wells identified in Permit Condition I.3. Results shall be reported in accordance with Permit Conditions II.D.3:

Parameter*	Units	Sample Type	Monitoring Frequency
Temperature	Deg F	Automated**	Quarterly
Water Level Relative to NAVD	ft	Automated	Quarterly
Specific Conductance	umhos/cm	Automated**	Quarterly
Salinity	PSU	Automated	Quarterly
Fluid Density	g/cm^3	Automated	Quarterly
pH	s.u.	Grab	Quarterly
Solids, Total Dissolved (TDS)	mg/L	Grab	Quarterly
Chloride (as Cl)	mg/L	Grab	Quarterly
Sodium, Total	mg/L	Grab	Quarterly
Calcium, Total	mg/L	Grab	Quarterly
Potassium, Total	mg/L	Grab	Quarterly
Iron, Total Recoverable	mg/L	Grab	Quarterly
Tritium[3]	pCi/L	Grab	Quarterly

[3] The permittee shall submit a summary of at least the latest twelve months of tritium results available by August 31 of each year in lieu of submitting the results on a discharge monitoring report.

Parameter*	Units	Sample Type	Monitoring Frequency
Nitrogen, Ammonia, Total (as N)	mg/L	Grab	Quarterly
Ammonium ion (NH_4^+)	mg/L	Grab	Quarterly
Ammonia, Total Unionized (as NH_3)	mg/L	Grab	Quarterly
Nitrite plus Nitrate, Total (as N)	mg/L	Grab	Quarterly
Nitrogen, Kjeldahl, Total (as N)	mg/L	Grab	Quarterly
Nitrogen, Total	mg/L	Grab	Quarterly
Phosphorus, Total (as P)	mg/L	Grab	Quarterly
Phosphate, Ortho (as PO_4)	mg/L	Grab	Quarterly
Boron, Total Recoverable	mg/L	Grab	Semi-Annually
Magnesium, Total Recoverable	mg/L	Grab	Semi-Annually
Sulfate, Total	mg/L	Grab	Semi-Annually
Sulfide	mg/L	Grab	Semi-Annually

[62-520.600(11)(b)]

*The above listed parameters are report except for Nitrite plus Nitrate, Total (as N), which has a limit of 10 mg/L in samples collected from monitoring wells TPGW-L3-18, and TPGW-L5-18.

** Because L and G wells are not automated, automated parameters shall be collected as grab samples on a quarterly basis. In addition, quarterly temperature and specific conductance profiles shall be collected at 1-foot intervals.

5. Monitoring wells TPGW- 1, 4, 5, 6, 17, 18, and 19 shall serve to aid in the determination of the success of the retraction of the hypersaline plume, as set out in Section VI of this permit.

6. In accordance with Chapter 62-160, F.A.C., records of the sampling protocol shall be maintained on-site for each monitoring well. This record shall include water level, total depth of the well, volume of water in the well, volume of water removed (during analytic sampling), stabilization documentation including pH, conductivity, and temperature; time interval of purging; time sample is taken; and device(s) used for purging (including discharge rate) and sampling. All records shall be kept on site and made available to the Department upon request.

7. In the event the water quality monitoring shows an exceedance of the applicable water quality standards for Nitrite plus Nitrate, Total (as N), the permittee shall arrange for a confirmation re-sampling within 15 days after the permittee's receipt of laboratory results. If the initial results demonstrate or the re-sampling confirms groundwater exceedances, the permittee shall notify the Department in writing within 14 days of this finding and the permittee shall be required to implement Department-approved corrective action to address the water quality violation and/or impacts within the timetable provided by the Department.

8. During well sampling, water levels shall be measured on the sample day and recorded prior to evacuating the wells or collecting samples. Water level, top of well casing and land surface elevations at each well site, at a precision of plus or minus 0.01 feet using a consistent, nationally recognized datum, shall be reported on each analysis report. Prior to sampling, the field parameters shall be stabilized from each well. Sampling and purging methods in the SOPs, as allowed in Chapter 62-160, F.A.C., must be used. *[62-520.600(11)(c)]*

9. Analyses shall be conducted on unfiltered samples, unless filtered samples have been approved by the Department's Southeast District Office as being more representative of groundwater conditions. *[62-520.310(5)]*

10. If any monitoring well becomes damaged or inoperable, the permittee shall notify the Department's Southeast District Office immediately and a detailed written report shall follow within seven days. The written report shall detail what problem has occurred and remedial measures that have been taken to prevent recurrence. All monitoring well design and replacement shall be approved by the Department's Southeast District Office prior to installation. *[62-520.600(6)(l)]*

11. All wells shall be plugged and abandoned in accordance with subsection 62-532.500(5), F.A.C., unless future use is intended. *[62-532.500(5)]*

12. The permittee shall provide verbal notice to the Department as soon as practical after discovery of a sinkhole within an area for the management or application of wastewater or sludge. In accordance with permit condition IX.20, the permittee shall immediately implement measures to control the entry of contaminants into waters.

II. SURFACE WATER EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

A. Surface Water Monitoring

1. Point source discharges, as defined in subsection 62-620.200(37), F.A.C., from the facility to surface waters of the State are not authorized under this permit.

2. The discharges approved by this permit shall not cause or contribute to a violation of the surface water quality standards or criteria in Rule 62-302, F.A.C.

3. The permittee shall not increase the temperature of the surrounding surface water bodies beyond the CCS periphery so as to cause substantial damage or harm to the aquatic life or vegetation therein or interfere with beneficial uses assigned to the surface water bodies. *[62-302.520(1)(a)]*

4. During the period of operation authorized by this permit, the permittee shall sample surface waters at surface water monitoring sites, designated as **Surface Water Monitoring Group D-01A,** as specified below and reported in accordance with Permit Condition II.D.3:

			Monitoring Requirements					
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Temperature, Water	Deg F	Max Max	Report Report	Daily Maximum Monthly Average	Monthly	In situ	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
pH	s.u.	Max Min	Report Report	Daily Maximum Daily Minimum	Quarterly	Grab or In situ	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Solids, Total Dissolved (TDS)	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Salinity	PSU	Max	Report	Daily Maximum	Monthly	In situ	SWD- 8, 9, 10, 11, 12	
				Monthly Average	Monthly	Calculated	SWD-1	
				Monthly Average	Monthly	In situ	SWD-8, 9, 10, 11, 12	
Specific Conductance	umhos/cm	Max	Report	Daily Maximum	Quarterly	In situ	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Turbidity	NTU	Max	Report	Daily Maximum	Quarterly	Grab	SWD-8, 9, 10, 11, 12	
Nitrogen, Ammonia, Total (as N)	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Ammonia, Total Unionized (as NH_3)	mg/L	Max	Report	Daily Maximum	Quarterly	Calculated	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Ammonium ion (NH_4^+)	mg/L	Max	Report	Daily Maximum	Quarterly	Calculated	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Nitrite plus Nitrate, Total (as N)	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Nitrogen, Kjeldahl, Total (as N)	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	

Parameter	Units	Max/ Min	Limit	Monitoring Requirements: Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Nitrogen, Total	mg/L	Max	Report	Single Sample	Quarterly	Calculated	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Phosphate, Ortho (as PO_4)	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Phosphorous, Total	mg/L	Max	Report	Single Sample	Quarterly	Grab	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Chlorophyll *a*	µg/L	Max	Report	Daily Maximum	Quarterly	Grab	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Copper, Total Recoverable	µg/L	Max	Report	Daily Maximum	Quarterly	Grab	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Iron, Total Recoverable	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Zinc, Total Recoverable	µg/L	Max	Report	Daily Maximum	Quarterly	Grab	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Boron, Total Recoverable	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Chlorides (as Cl)	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
				Monthly Average	Monthly	Calculated	SWD-1	
Magnesium, Total Recoverable	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Sodium, Total Recoverable	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Sulfate, Total	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Tritium[4]	pCi/L	Max	Report	Daily Maximum	Quarterly	Grab	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	

5. Surface water samples shall be taken at the monitoring locations described below for the parameters listed in Permit Condition II.A.4.:

Monitoring Site Number	Sample Station ID	Location	Latitude			Longitude		
			°	'	"	°	'	"
SWD-1	--	The average of the following six salinity and chlorides monitoring locations in Biscayne Bay (TPBBSW-3, TPBBSW-4, TPBBSW-5, TPBBSW-7, TPBBSW-10, TPBBSW-14).						
SWD-2	TPBBSW-3 (bottom and top)	Biscayne Bay	25	23	49.38	80	18	14.82
SWD-3	TPBBSW-4 (bottom and top)	Biscayne Bay	25	20	40.34	80	19	43.90
SWD-4	TPBBSW-5 (bottom and top)	Biscayne Bay	25	19	13.69	80	22	1.70
SWD-5	TPBBSW-7T (bottom and top)	Biscayne Bay near Turtle Point Canal Dam	25	25	9.99	80	19	42.15
SWD-6	TPBBSW-10 (bottom and top)	Biscayne Bay	25	26	27.83	80	19	22.92
SWD-7	TPBBSW-14 (bottom and top)	Biscayne Bay	25	25	15.50	80	19	34.50

[4] The permittee shall submit a summary of at least the latest twelve months of tritium results available by August of each year in lieu of submitting the results on a discharge monitoring report.

SWD-8	TPSWC-1B (bottom) TPSWC-1T (top)	L-31E Canal	25	25	58.44	80	21	11.87
SWD-9	TPSWC-2B (bottom) TPSWC-2T (top)	L-31E Canal	25	24	21.20	80	21	46.30
SWD-10	TPSWC-3B (bottom) TPSWC-3T (top)	L-31E Canal	25	22	10.47	80	22	33.00
SWD-11	TPSWC-4B (bottom) TPSWC-4T (top)	S-20 Canal	25	21	24.10	80	22	3.00
SWD-12	TPSWC-5B (bottom) TPSWC-5T (top)	Card Sound Canal at Hotel 2 Dam	25	21	24.62	80	20	18.70

6. Top samples shall be collected 0.5 m below the water surface. Bottom samples shall be collected 0.5 m above the sediment. Bottom samples may be modified to avoid sediment in samples.

B. Internal Outfalls

1. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to release non-process wastewater, consisting of OTCW, AECW, cooling tower blowdown, LVW, and stormwater. LVW consists of chemical treatment system wastewater, heat recovery steam generator blowdown, reverse osmosis concentrate, and condensate polishing system backwash water. Stormwater from equipment and containment areas is treated via oil/water separators prior to entering the CCS, as indicated in the permit renewal application, from **Internal Outfall I-001** to the on-site feeder canal within the CCS. Such releases shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition II.D.3:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Temperature, Water	Deg F	Max Max	Report Report	Daily Maximum Monthly Average	Monthly	In situ	OUI-1	
Solids, Total Suspended	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	OUI-1	
Biochemical Oxygen Demand (BOD)	mg/L	Max	Report	Daily Maximum	Monthly	Grab	CAL-1	
Dissolved Oxygen (DO), % Saturation	Percent	Min	Report	Monthly Average	Monthly	Calculated	CAL-1	
Oxygen Reduction Potential	mv	Max	Report	Daily Maximum	Monthly	Meter	CAL-1	
pH	s.u.	Max Min	Report Report	Daily Maximum Daily Minimum	Quarterly	Grab	OUI-1	
Color	PCU	Max	Report	Daily Maximum	Monthly	Grab	OUI-1	
Solids, Total Dissolved	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	OUI-1	
Salinity	PSU	Max	Report	Daily Maximum	Monthly	Grab	CAL-1	See II.B.4
				Monthly Average	Monthly	Grab	CAL-1	
			Report	Annual Average	Daily	Grab	CAL-1	
Specific Conductance	μmhos/cm	Max	Report	Daily Maximum	Quarterly	Grab	CAL-1	
Turbidity	NTU	Max	Report	Daily Maximum	Quarterly	Grab	CAL-2	
Nitrogen, Ammonia, Total (as N)	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	OUI-1, CAL-1	
Ammonia, Total Unionized (as NH_3)	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	OUI-1, CAL-1	
Ammonium ion (NH_4^+)	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	OUI-1, CAL-1	

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Nitrite plus Nitrate, Total (as N)	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	OUI-1, CAL-1	
Nitrogen, Kjeldahl, Total (as N)	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	OUI-1, CAL-1	
Nitrogen, Total	mg/L	Max	Report	Single Sample	Quarterly	Calculated	OUI-1, CAL-1	
Phosphate, Ortho (as PO_4)	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	OUI-1, CAL-1	
Phosphorous, Total	mg/L	Max	Report	Single Sample	Quarterly	Grab	OUI-1, CAL-1	
Chlorophyll *a*	µg/L	Max	Report	Daily Maximum	Quarterly	Grab	OUI-1, CAL-1	
Copper, Total Recoverable	µg/L	Max	Report	Daily Maximum	Semi-annually	Grab	OUI-1, CAL-1	
Iron, Total Recoverable	mg/L	Max	Report	Daily Maximum	Semi-annually	Grab	OUI-1, CAL-1	
Zinc, Total Recoverable	µg/L	Max	Report	Daily Maximum	Semi-annually	Grab	OUI-1, CAL-1	
Boron, Total Recoverable	mg/L	Max	Report	Daily Maximum	Semi-annually	Grab	OUI-1	
Chlorides (as Cl)	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	OUI-1	
Magnesium, Total Recoverable	mg/L	Max	Report	Daily Maximum	Semi-annually	Grab	OUI-1	
Sodium, Total Recoverable	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	OUI-1	
Sulfate, Total	mg/L	Max	Report	Daily Maximum	Semi-annually	Grab	OUI-1	
Sulfide, Total	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	CAL-1	
Tritium[5]	pCi/L	Max	Report	Daily Maximum	Quarterly	Grab	OUI-1	

2. Samples shall be taken at the monitoring locations described below for the parameters listed in Permit Condition II.B.1.:

Monitoring Site Number	Sample Station ID	Location	Latitude			Longitude		
			o	'	"	o	'	"
OUI-1	--	Cooling water discharge prior to entering the feeder canal to the CCS	25	26	00.60	80	20	15.64
CAL-1	--	--	Average of CCS monitoring sites OUI-2, -3, -4, -5, -6, -7, and -8.					
CAL-2	--	--	Average of CCS monitoring sites OUI-2, -4, -7, and -8.					
OUI-2	TPSWCCS-1	Northwest corner of the CCS	25	25	56.0	80	21	00.8
OUI-3	TPSWCCS-2	Central portion of the CCS	25	23	39.0	80	21	06.7
OUI-4	TPSWCCS-3	Southwestern portion of the CCS	25	21	52.4	80	22	02.4
OUI-5	TPSWCCS-4	Southern portion of the CCS near the Hotel 2 Dam	25	21	25.3	80	20	23.1
OUI-6	TPSWCCS-5	East-central portion of the CCS	25	23	18.4	80	19	54.4
OUI-7	TPSWCCS-6	Northeastern portion of the CCS	25	25	56.2	80	19	40.2
OUI-8	TPSWCCS-7	West-central portion of the CCS	25	24	07.6	80	21	39.4

[5] The permittee shall submit a summary of at least the latest twelve months of tritium results available by August of each year in lieu of submitting the results on a discharge monitoring report.

3. The daily salinity readings from the CCS shall be compiled each quarter to create a quarterly average for each of the CCS. The automated hourly data as well as the analytical results from the existing individual stations shall be made available via FPL's EDMS.

4. FPL shall, when monitoring the salinity levels in the CCS, utilize all available monitoring resources in the CCS to obtain the average annual salinity rate. Specific monitoring points may not be excluded from the calculation unless such exclusion is allowed by the Department based upon a scientific reason. For the purposes of determining average annual salinities for the CCS, FPL shall use qualified hourly data (pursuant to the approved 2009 Monitoring Plan QAPP) from each of the CCS monitoring sites TPSWCCS-1, 2, 3, 4, 5, 6, and 7 collected beginning at 00:00 through 23:59 each day. The qualified hourly data for the day will be summed and divided by the number of qualified hourly values for the station that day. Stations with fewer than 12 qualified hourly data values in a given day shall not be used in the calculation of the CCS daily average. The daily averages for all qualified stations (up to seven per day) for a given day will be summed and divided by the number of qualified stations for that day to produce a qualified CCS daily average salinity value. The average annual salinity is calculated by summing the qualified CCS daily average salinity values from June 1st through May 31st and dividing the value by the number of days in the year. *[Consent Order OGC File Number 16-0241, paragraph 29.j]*

5. The permittee shall submit to the Tallahassee Wastewater Management Program a copy of the Turkey Point Annual Crocodile Monitoring Report, and a copy of the Ecological Monitoring section and associated data contained in the Turkey Point Plant Annual Monitoring Report required by Conditions XVII.C and X, respectively, of the Conditions of Certification (License No. PA 03-45). In addition, the permittee shall provide a copy of comments or findings to the Department upon request.

C. Porewater Monitoring

1. During the period of operation authorized by this permit, the permittee shall sample porewater (free water present in sediments) from coastal marine wetlands north, east, and south of the CCS from monitoring sites, designated as **Porewater Outfall D-02A,** at locations described below in accordance with the protocols set forth in FPL's Quality Assurance Project Plan dated 2013:

Porewater Monitoring ID	Description of Monitoring Location	Latitude			Longitude		
PW M1-2	Coastal marine wetlands; ½ mile north of power block	25	26	49.8	80	19	57.7
PW M2-2	Coastal marine wetlands; east of CCS, 2 miles south of power block	25	24	18.8	80	19	47.6
PW M3-2	Coastal marine wetlands; east of CCS, 3.4 miles south of power block	25	23	4.2	80	19	40.6
PW M4-2	Coastal marine wetlands; southeast corner of CCS	25	21	16.8	80	19	44.9
PW M5-2	Coastal marine wetlands; south of CCS	25	20	56	80	20	33

PW M6-1	Coastal marine wetlands; west of Card Sound Road (background location)	25	17	40.1	80	23	46.8

2. During the period of operation authorized by this permit, the permittee shall sample porewater as specified below and reported in accordance with Permit Condition II.D.3.

Parameter*	Units	Sample Type	Monitoring Frequency
Temperature	Deg F	Grab	Semi-Annually
pH	s.u.	Grab	Semi-Annually
Specific Conductance	µmhos/cm	Grab	Semi-Annually
Salinity	PSU	Grab	Semi-Annually
Fluid Density	g/ml	Grab	Semi-Annually
Solids, Total Dissolved (TDS)	mg/L	Grab	Semi-Annually
Chloride (as Cl)	mg/L	Grab	Semi-Annually
Sodium, Total Recoverable	mg/L	Grab	Semi-Annually
Calcium, Total Recoverable	mg/L	Grab	Semi-Annually
Potassium, Total	mg/L	Grab	Semi-Annually
Boron, Total Recoverable	mg/L	Grab	Semi-Annually
Copper, Total Recoverable	ug/L	Grab	Semi-Annually
Iron, Total Recoverable	mg/L	Grab	Semi-Annually
Magnesium, Total Recoverable	mg/L	Grab	Semi-Annually

Zinc, Total Recoverable	ug/L	Grab	Semi-Annually
Sulfate, Total	mg/L	Grab	Semi-Annually
Tritium[5]	pCi/L	Grab	Semi-Annually
Nitrogen, Ammonia, Total (as N)	mg/L	Grab	Semi-Annually
Ammonium ion (as NH_4)	mg/L	Grab	Semi-Annually
Ammonia, Total Unionized (as NH_3)	mg/L	Grab	Semi-Annually
Nitrite plus Nitrate, Total (as N)	mg/L	Grab	Semi-Annually
Nitrogen, Kjeldahl, Total (as N)	mg/L	Grab	Semi-Annually
Nitrogen, Total (as N)	mg/L	Grab	Semi-Annually
Phosphorus, Total (as P)	mg/L	Grab	Semi-Annually
Phosphate, Ortho (as PO_4)	mg/L	Grab	Semi-Annually

D. Other Limitations and Monitoring and Reporting Requirements

1. The sample collection, analytical test methods, and method detection limits (MDLs) applicable to this permit shall be conducted using a sufficiently sensitive method to ensure compliance with applicable water quality standards and effluent limitations and shall be in accordance with a Department-approved methodology or in accordance with Rule 62-4.246, Chapters 62-160 and 62-601, F.A.C., and 40 CFR 136, as appropriate. The list of Department established analytical methods, and corresponding MDLs and PQLs (practical quantitation limits), which is titled "FAC 62-4 MDL/PQL Table (April 26, 2006)" is available at http://www.dep.state.fl.us/labs/library/index.htm. The MDLs and PQLs as described in this list shall constitute the minimum acceptable MDL/PQL values and the Department shall not accept results for which the laboratory's MDLs or PQLs are greater than those described above unless alternate MDLs and/or PQLs have been specifically approved by the Department for this permit. Any method included in the list may be used for reporting as long as it meets the following requirements:

   a. The laboratory's reported MDL and PQL values for the particular method must be equal or less than the corresponding method values specified in the Department's approved MDL and PQL list;

   b. The laboratory reported MDL for the specific parameter is less than or equal to the permit limit or the applicable water quality criteria, if any, stated in Chapter 62-302, F.A.C. Parameters that are listed as "report only" in the permit shall use methods that provide an MDL, which is equal to or less than the applicable water quality criteria stated in Chapter 62-302, F.A.C.; and

c. If the MDLs for all methods available in the approved list are above the stated permit limit or applicable water quality criteria for that parameter, then the method with the lowest stated MDL shall be used.

When the analytical results are below method detection or practical quantitation limits, the permittee shall report the actual laboratory MDL and/or PQL values for the analyses that were performed following the instructions on the applicable discharge monitoring report.

Where necessary, the permittee may request approval of alternate methods or for alternative MDLs or PQLs for any approved analytical method. Approval of alternate laboratory MDLs or PQLs are not necessary if the laboratory reported MDLs and PQLs are less than or equal to the permit limit or the applicable water quality criteria, if any, stated in Chapter 62-302, F.A.C. Approval of an analytical method not included in the above-referenced list is not necessary if the analytical method is approved in accordance with 40 CFR 136 or deemed acceptable by the Department. *[62-4.246, 62-160]*

2. The permittee shall provide safe access points for obtaining representative influent and effluent samples which are required by this permit. *[62-620.320(6)]*

3. Monitoring requirements under this permit are effective on the first day of the second month following the effective date of the permit. Until such time, the permittee shall continue to monitor and report in accordance with previously effective permit requirements, if any. During the period of operation authorized by this permit, the permittee shall complete and submit to the Department Discharge Monitoring Reports (DMRs) in accordance with the frequencies specified by the REPORT type (i.e., monthly, quarterly, semiannual, annual, etc.) indicated on the DMR forms attached to this permit. Unless specified otherwise in this permit, monitoring results for each monitoring period shall be submitted in accordance with the associated DMR due dates below. DMRs shall be submitted for each required monitoring period including periods of no release of wastewater.

4.

REPORT Type on DMR	Monitoring Period	Submit by
Monthly	first day of month – last day of month	28th day of following month
Quarterly	January 1 - March 31 April 1 – June 30 July 1 – September 30 October 1 – December 31	April 28 July 28 October 28 January 28
Semiannual	January 1 – June 30 July 1 – December 31	July 28 January 28
Annual	January 1 – December 31	January 28

The permittee shall use the electronic DMR system approved by the Department (EzDMR) and shall electronically submit the sample results as an attachment to the EzDMR submittal, in accordance with Permit Condition I.C.3., using the DEP Business Portal at http://www.fldepportal.com/go/, unless the permittee has a waiver from the Department in accordance with 40 CFR 127.15. Reports shall be submitted to the Department by the twenty-eighth (28th) of the month following the month of operation.

[62-620.610(18)]

5. Unless specified otherwise in this permit, all reports and other information required by this permit, including 24-hour notifications, shall be submitted to or reported to, as appropriate, the Department's Southeast District Office at the address specified below:

Florida Department of Environmental Protection
Southeast District
3301 Gun Club Road, MSC7210-1
West Palm Beach, Florida 33406

Phone Number - (561) 681- 6600

FAX Number - (561) 681-6755 (All FAX copies shall be followed by original copies.)

[62-620.305]

6. All reports and other information shall be signed in accordance with the requirements of Rules 62-620.305 and 62-620.310, F.A.C. *[62-620.305, 62-620.310]*

7. If there is no release of wastewater from internal outfall I-001 on a day when the facility would normally sample, the sample shall be collected on the day of the next release. *[62-620.320(6)]*

8. Wastewater shall not contain components that, alone or in combination with other substances or in combination with other components of the discharge:

   a. Settle to form putrescent deposits; or
   b. Float as debris, scum, oil, or other matter in such amounts as to form nuisances; or
   c. Produce color, odor, turbidity, or other conditions in such degree as to create a nuisance; or
   d. Are acutely toxic; or
   e. Are present in concentrations which are carcinogenic, mutagenic, or teratogenic to human beings or to significant, locally occurring, wildlife or aquatic species; or
   f. Pose a serious danger to the public health, safety, or welfare.

   [62-620.320(6), 62-302.500(1)]

9. There shall be no release of polychlorinated biphenyl (PCB) compounds such as those commonly used for transformer fluid to the waters of the State or the CCS. The permittee shall dispose of all known PCB equipment, articles, and wastes either in accordance with:

   a. Department-issued permits governing soil thermal treatment (Chapter 62-713, F.A.C.) or Department-approved landfills provided the PCB concentrations meet the Florida landfill's permitted limit when concentrations are less than 50 ppm; or

   b. 40 CFR 761 when concentrations are greater than or equal to 50 ppm.

   [40 CFR Part 423.12(b)(2)]

10. Discharge of any product registered under the Federal Insecticide, Fungicide, and Rodenticide Act to any waste stream that ultimately may be released to the CCS or waters of the State is prohibited unless specifically authorized elsewhere in a permit; except this requirement is not applicable to products used for lawn and agricultural purposes or to the use of herbicides if used in accordance with labeled instructions and any applicable State permit. In the event the permittee proposes to use water treatment chemicals, biocides, corrosion inhibitors, or additives not authorized in this permit, or not previously reported to the Department, that ultimately may be released to the CCS or waters of the State, the permittee shall notify the Department in writing a minimum of thirty (30) days prior to instituting the use of such product. The product shall not be used prior to a determination by the Department that a permit revision is not required or prior to Department approval. Such notification shall include:

    a. Name and general composition of biocide or chemical

    b. Frequencies of use

    c. Quantities to be used

    d. Proposed effluent concentrations

    e. Acute and/or chronic toxicity data (laboratory reports shall be prepared<u>, depending on the test type,</u> according to Section 12 of EPA document no. EPA-821-R-02-012 entitled, Methods for Measuring the Acute Toxicity of Effluents and Receiving Waters for Freshwater and Marine Organisms, <u>Section 10 of EPA document no. EPA-821-R-02-013 entitled, Short-term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Freshwater Organisms or Section 10 of EPA document no. EPA-821-</u>

R-02-014 entitled, Short-term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Marine and Estuarine Organisms, or most current addition)

f. Product data sheet

g. Product label

A revision to this permit is not necessary for use of products equivalent to those authorized in this permit provided the equivalent products consist of the same active ingredients and the product is applied at the same location with the same or lower concentrations of the active ingredients at the outfall. The permittee is responsible for maintaining documentation on-site which demonstrates equivalency of any new water treatment products from another vendor or manufacturer with a different product name from those listed above.

11. Discharge of any waste resulting from the combustion of toxic, hazardous, or metal cleaning wastes to any waste stream which ultimately reaches the CCS or waters of the State is prohibited, unless specifically authorized elsewhere in this permit.

12. The permittee shall not store soil or other similar erodible materials in a manner in which off-site runoff is uncontrolled, nor shall construction activities be conducted in a manner which produces uncontrolled off-site runoff unless such uncontrolled runoff has been specifically approved by the Department. "Uncontrolled" shall mean without sedimentation basin or other controls approved by the Department.

13. The permittee shall operate and maintain loading and unloading facilities in such a manner in order to preclude spillage of chemicals, etc., used at the facility, and shall take all actions necessary to clean-up and control any such spill which may occur.

14. Any water drained from the fuel oil storage tanks or other water which meets the definition of "Petroleum Contact Water" as defined in subsection 62-740.030(1), F.A.C., shall be disposed at a Department-approved facility in accordance with Chapter 62-740, F.A.C.

15. The permittee is authorized to utilize the following water treatment chemicals and biocides, or their equivalents, in the cooling water systems and other wastewater streams:

Chemical Name	Purpose	Dosage (mg/L)	Units Treated	Frequency
Hydrazine	Normal Operation Oxygen Scavenger	40 - 500	3, 4	Daily
Hydrazine	Wet Layup Oxygen Scavenger	25 - 300	3, 4	Outages Only
Carbohydrazide	Oxygen Scavenger	25 - 100	3, 4	Outages Only
Carbohydrazide	Oxygen Scavenger	60 - 700	3, 4	Daily
Dimethylamine	pH Control	0.1 - 1.0	3, 4	Daily
Monoethanolamine	pH Control	3 - 6	3, 4	Daily
Lithium Hydroxide	pH Control for Reactor Coolant System	0 - 6	3, 4	As Needed
ROClean P111	Reverse Osmosis Membrane Cleaning	150 - 300	5	Batch
Sodium Molybdate	Corrosion Inhibitor – Recirculating Cooling System	160 - 1000	All	As Needed
Tolytriazole	Corrosion Inhibitor – Copper Control	10 - 100	All	As Needed
Sodium Nitrite	Corrosion Inhibitor – Recirculating Cooling System	50 - 1500	3, 4	As Needed
Sodium Hydroxide	pH Control - Recirculating Cooling System	Maintain pH 8.5 - 11	3, 4	As Needed
Sodium Hydroxide	Reverse Osmosis Operation	Maintain pH of 9.06	5	Monthly, Batch
Sodium Hydroxide	Reverse Osmosis pH Control	Maintain pH > 8.1	3, 4	Daily
Sodium Hypochlorite 12%	Cooling Tower Biocide	Maintain 0.2 - 1 residual	5	Daily
Sodium Hypochlorite	Disinfectant/Oxidizer	1-2	Plant General Use	As Needed
Sodium Hypochlorite	Oxidize Organics	1-2	Cooling Canals	As Needed
Versene 100 (EDTA)	Reverse Osmosis Membrane Cleaning	3000 - 5200	5	Batch
Citric Acid	Reverse Osmosis Membrane Cleaning	30,000	5	Batch
Hypersperse MDC704i	Reverse Osmosis Membrane Cleaning	2.5	5	Daily

Chemical Name	Purpose	Dosage (mg/L)	Units Treated	Frequency
ENDCOR UAN 9766 (Molybdate)	Auxiliary Equipment Cooling Water System	5 gal./mo. (solid)	5	As Needed
AZ8101 (Tolytriazole)	Auxiliary Equipment Cooling Water System	2.5 gal./mo. (solid)	5	As Needed
OPTISPERSE HP3100	Boiler Drum Corrosion Inhibitor	2 - 3	5	Daily
DEPOSITROL PY5200	Cooling Tower Deposit Control	1.3	5	Daily
DEPOSITROL BL5400	Cooling Tower Scale Inhibitor	0.75	5	Daily
Ammonium Hydroxide	pH Control	3 - 20	3, 4	Daily
Ammonium Hydroxide	Condensate and Feedwater pH Control	Maintain pH of 9.68	5	Daily
OPTISPERSE PWR6600	Iron Oxide Dispersant in Steam Gen.	0 - 1	3, 4	Outages Only
OPTISPERSE PWR6600	Iron Oxide Dispersant in Steam Gen.	< 10 ppb	3, 4	Daily
VITEC 3000	Reverse Osmosis Antiscalant – potable water supply	3	3, 4	Batch
Sodium Bisulfite 40%	Reverse Osmosis Dechlorination	2-3/1-2	3, 4	Daily
Sodium Bisulfite 40%	Dechlorination	1-2	Cooling Canals, Plant General Use	As Needed
Hydrogen Peroxide 50%	Reverse Osmosis Hydrogen Sulfide Mitigation – Well Water	7-10	3, 4	Daily
Vitec 5100	Reverse Osmosis Antiscalant	5	3, 4	Daily
Vitec 1000	Reverse Osmosis Antiscalant	2	3, 4	Daily
Wood Flour	Condenser Tube Leak Temporary Repair	200 lb/min. (Max.) Less than 1000 lb/wk	3, 4	As Needed
Quaternary Ammonium Salt	Biological Fouling Control - Recirculating Cooling System	6 - 12	3, 4	As Needed
Gluteraldehyde	Biological Fouling Control - Recirculating Cooling System	250-500	3, 4	As Needed
MBC 215 (Isothiazolin)	Biological Fouling Control - Recirculating Cooling System	15	3, 4	As Needed
Sodium Dichromate	Corrosion Inhibitor for Emergency Diesel Gen. - Recirculating Cooling System	3500 - 4500	3, 4	As Needed
Sulfuric Acid 98%	pH Control for Water Treatment Plant to Degas CO_2	Maintain pH 6 - 7	3, 4	Daily
Sulfuric Acid	Cooling Tower pH Control	350	5	Daily
Boric Acid	Process Chemical for Chemical Volume Control System	0 - 2600	3, 4	As Needed
Aluminum-based Flocculents (such as Liquid Alum, Green Bullet, WALLFLOC 5050, or Equivalent)	Coagulation of Algae and Nutrients	250 (Max.)	Cooling Canals	As Needed
Xanthene Dyes or Equivalent (Yellow, Green, Red, or Violet Dyes)	Dye Studies for Leaks or Flow Monitoring	1	Plant General Use	As Needed
Optisperse PWR6000	Dispersant	≤ 20 ppb daily use ≤ 1 mg/l during outages	3, 4	Daily

16. Hydrazine from plant layup water during overhauls and/or refueling outages shall be measured at the outlet from the unit being serviced. Sampling shall be once per day of discharge by grab sample at the maximum expected concentration. Results of sampling will be submitted to the Department upon request. To determine the hydrazine concentration being released to the CCS, the following equation shall be used:

$$\frac{\textit{(B/S) Blowdown Flow x (B/S) Hydrazine Concentration}}{\textit{Once-through Cooling Water Flow}} = \textit{Hydrazine concentration at the recirculating cycle cooling canal system}$$

*Where (B/S) refers to boiler or steam generator

In the event that any value exceeds 3.4 mg/L, the permittee shall immediately modify its release pattern and resample. The Department's Southeast District Office shall be notified of the situation in accordance with permit condition IX.20.

17. Non-discharging/Closed Loop Vehicle Wash Recycle System Requirements.

    a. No discharge of recycle system wastewater, including filter backwash water, is authorized to waters of the State or to groundwater.

    b. The operation of the rainwater diversion system, oil/water separator, and placard posting shall be addressed and included in the facility's Best Management Practices Pollution Prevention Plan (PLAN) in accordance with permit condition VII.

18. Nothing in this permit authorizes take for the purposes of the permittee's compliance with the federal Endangered Species Act. [40 CFR 125.98(b)(1)]

19. A revision to this permit is not necessary for the following activities:

    a. Structural changes that do not change the quality, nature, or quantity of the discharge of wastes or that do not cause water pollution to Waters of the State; and

    b. Construction, replacement or repair of components at the facility which does not change the permitted treatment works or the terms and conditions of this permit.

    Records of these activities shall be kept by the permittee (activity description, start date and length of activity). The documentation shall be kept on-site in accordance with Permit Condition V.2, and made available to Department staff upon request. *[62-620.200(26)(a) and (b)]*

20. The facility will take reasonable actions to select appropriate laboratories with sufficient capacity to avoid delay in receiving results due to backlogs. If such delay occurs, the facility will make reasonable efforts to resolve those delays. *[Consent Order OGC File Number 16-0241, paragraph 30]*

III. SLUDGE, SOLIDS, AND VEGETATIVE MATTER MANAGEMENT REQUIREMENTS

1. The permittee shall be responsible for proper treatment, management, use, and disposal of its sludges. *[62-620.320(6)]*

2. Storage, transportation, and disposal of sludge/solids characterized as hazardous waste shall be in accordance with requirements of Chapter 62-730, F.A.C. *[62-730]*

3. Sludge or other solids generated from the facility shall be reused, reclaimed, or otherwise disposed of in accordance with the requirements of Chapter 62-701, F.A.C. Disposal of sludge in a solid waste disposal facility shall be in accordance with the requirements of Chapter 62-701, F.A.C. *[62-701]*

4. Vegetation and materials removed from intake screens and vegetation, sediments and sludge excavated from the CCS or basins must be properly stored on-site until they are disposed in accordance with requirements in Chapter 62-701, F.A.C., and other applicable State and Federal requirements. Vegetation and materials shall be handled and managed in accordance to the Best Management Practices Plan in Section VII of this permit.

5. The permittee shall keep records of the amount of industrial sludge, solids, and vegetative matter disposed, transported, or incinerated. If a person other than the permittee is responsible for sludge transporting, disposal, or incineration, the permittee shall also keep the following records:

    a. name, address and telephone number of any transporter, and any manifests or bill of lading used;

    b. name and location of the site of disposal, treatment or incineration;

    c. name, address, and telephone number of the entity responsible for the disposal, treatment, or incineration site.

IV. ADDITIONAL LAND APPLICATION REQUIREMENTS

Section IV is not applicable to this facility.

V. CONSTRUCTION, OPERATION AND MAINTENANCE REQUIREMENTS

1. During the period of operation authorized by this permit, the wastewater facilities shall be operated under the supervision of a person who is qualified by formal training and/or practical experience in the field of water pollution control. *[62-620.320(6)]*

2. The permittee shall maintain the following records and make them available for inspection on the site of the permitted facility.

   a. Records of all compliance monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, including, if applicable, a copy of the laboratory certification showing the certification number of the laboratory, for at least three years from the date the sample or measurement was taken;

   b. Copies of all reports required by the permit for at least three years from the date the report was prepared;

   c. Records of all data, including reports and documents, used to complete the application for this permit for at least three years from the date the application was filed;

   d. Records of all disposal of vegetation and materials removed from intake screens and vegetation, sediments and sludge removed from wastewater and stormwater basins;

   e. A copy of the current permit;

   f. A copy of any required record drawings;

   g. Copies of the logs and schedules showing plant operations and equipment maintenance for three years from the date of the logs or schedules; and

   h. All pertinent impoundment permits, design, construction, operation, and maintenance information, including but not limited to, plans, geotechnical and structural integrity studies, copies of permits, associated certifications by qualified, State-registered professional engineer, and regulatory approvals.

   [62-620.350]

3. During the period of operation authorized by this permit, the wastewater facility shall, as part of the regular maintenance schedule, review the structural integrity of all outfalls, including all outfalls which have been taken out of service.

VI. SCHEDULES

1. The following improvement actions shall be completed according to the following schedule. The Plan shall be prepared and implemented in accordance with Part VII of this permit.

Improvement Action	Completion Date
1. Develop Best Management Practices Plan (Plan)	Effective date of permit plus 18 months
2. Implement Plan	Effective date of permit plus 30 months
3. Plan Summary	Effective date of permit plus 3 years

2. If the permittee plans to continue operation of this wastewater facility after the expiration date of this permit, the permittee shall submit an application for renewal no later than one-hundred and eighty days (180) prior to the expiration date of this permit. Application shall be made using the appropriate forms listed in Rule 62-620.910, F.A.C., including submittal of the appropriate processing fee set forth in Rule 62-4.050, F.A.C.

   [62-620.335(1) and (2)]

3. The permittee shall submit to the Department's Tallahassee Wastewater Management Program an annual report by August of each year as described in permit condition VIII.G.1. Where required by Chapter 471 (P.E.) or Chapter 492 (P.G.) F.S., applicable portions of the report shall be signed and sealed by the professional(s) who prepared them.

4. The facility shall submit annually by August of each year, following permit issuance, a nutrient monitoring summary report based on 12 months of groundwater, surface water, and CCS monitoring data to the Department's Tallahassee Wastewater Management Program. Where required by Chapter 471 (P.E.) or Chapter 492 (P.G.) F.S., applicable portions of the report shall be signed and sealed by the professional(s) who prepared them. The report shall include by station and depth where specified:

   a. Annual geometric mean (AGM) concentrations by nutrient parameter;

   b. Arithmetic mean;

   c. Percentiles including 25th, 75th, and 90th, number of samples collected by parameter; and

   d. Evaluation of trends over the period of record by parameter.

5. In lieu of submitting the results on a discharge monitoring report, the permittee shall submit to the Department's Tallahassee Wastewater Management Program and Southeast District Office a summary of at least the latest twelve months of tritium results for all locations where tritium is monitored by August of each year. Where required by Chapter 471 (P.E.) or Chapter 492 (P.G.) F.S., applicable portions of the report shall be signed and sealed by the professional(s) who prepared them.

6. In lieu of submitting the results on a discharge monitoring report, the permittee shall submit to the Department's Tallahassee Wastewater Management Program and Southeast District Office a summary of at least the latest twelve months for all parameters listed in permit condition I.4 in all wells listed in permit condition I.3 by August of each year. Where required by Chapter 471 (P.E.) or Chapter 492 (P.G.) F.S., applicable portions of the report shall be signed and sealed by the professional(s) who prepared them.

7. The permittee shall notify the Department's Tallahassee Wastewater Management Program following completion of the scheduled January 1, 2019 demolition and fill of the solids settling basins that formerly serviced Units 1 and 2.

8. The phrase "hypersaline water" as used in this permit means water that exceeds 19,000 mg/L chlorides. Location, volume and movement of the hypersaline plume shall be determined by Continuous Surface Electromagnetic Mapping ("CSEM") technology, as supplemented by data from the groundwater monitoring wells in Section I.

9. The permittee shall halt the westward migration of the hypersaline plume from the CCS within three years of the commencement of the remediation project (May 15, 2018). For determining compliance, the westward migration of the hypersaline plume shall be deemed halted if the third CSEM survey shows no net increase in hypersaline water volume and no net westward movement in the leading edge of the hypersaline plume. To ensure overall remediation objectives are attained in a timely manner, if the second CSEM survey indicates that the net westward migration of the hypersaline plume is not being halted, then, within 180 days of the second CSEM survey, the permittee shall develop and submit for approval to the Department a plan with specific actions to achieve the objectives of the remediation project. If the third CSEM survey still indicates the net westward migration of the hypersaline plume has not halted, the permittee shall implement the approved additional measures consistent with the Department approved schedule.

10. The permittee shall retract the hypersaline plume to the L-31E canal within ten years of the commencement of the remediation project (May 15, 2018). At the conclusion of the fifth year of operation of the remediation project (May 16, 2023), the permittee shall evaluate and report to the Department, within 180 days, the effectiveness of the system in retracting the hypersaline plume to the L-31E canal within 10 years. If this report shows the remediation project will not retract the hypersaline plume to the L-31E canal within 10 years due to adverse environmental impacts of remedial measures or other technical issues, the permittee shall provide an alternate plan for Department review and approval. The permittee shall begin implementing the alternate plan. in accordance with the Department approved schedule.

VII. BEST MANAGEMENT PRACTICES PLAN (PLAN)

A. General

Through implementation of the Plan the permittee shall prevent or minimize the generation and the potential for the release of pollutants (including mercury, copper, iron, zinc, and nutrients) from facility operations (including spillage, leaks, and material and waste handling and storage activities) to industrial wastewater and stormwater. The permittee must implement the provisions of the Plan required under this Part as a condition of this permit.

In accordance with Section 304(e) and 402(a)(2) of the Clean Water Act (CWA) as amended, 33 U.S.C. §§ 1251 et seq., and the Pollution Prevention Act of 1990, 42 U.S.C. §§ 13101-13109, the permittee must develop and implement the Plan for the facility covered by this permit, prepared in accordance with good engineering practices and in accordance with the factors outlined in 40 CFR §125.3(d)(2) or (3) as appropriate. Paragraph 62-620.100(3)(m), F.A.C., incorporates by reference 40 CFR 122.44(k), which contains guidelines for requiring Best Management Practices (BMPs) for facilities and activities regulated under Section 403.0885, F.S.

1. The Plan shall include industrial wastewater and stormwater BMPs. The Plan shall be consistent with the objectives in VII.B, Industrial Wastewater Best Management Practices, and VII.C, Stormwater Best Management Practices, and the general guidance contained in the publications entitled <u>Guidance Manual for Developing Best Management Practices (BMPs)</u> [EPA 833-B-93-004, October 1993]; <u>Developing Your Stormwater Pollution Prevention Plan: A Guide for Industrial Operators</u> [EPA 833-B-09-002, February 2009] or any subsequent revisions to these guidance documents.
2. The Plan shall specify the individual(s) or position(s) within the facility organization as members of a Plan Team that are responsible for developing the Plan and assisting the facility or operations manager in its implementation, maintenance, and revision. The Plan shall clearly identify the responsibilities of each team member. The activities and responsibilities of the team shall address all aspects of the facility's Plan.
3. The Plan shall be documented in narrative form, shall include any necessary plot plans, drawings or maps, and shall be developed in accordance with good engineering practices. The Plan shall be organized and written with the following structure:
   a. Name and location of the facility.
   b. Statement of Plan policy.
   c. Structure, functions, and Standard Operating Procedures (SOPs) of the Plan committee.
   d. Specific industrial wastewater and stormwater management practices and SOPs, including, but not limited to, the following:
      1. modification of equipment, facilities, technology, processes, and procedures,
      2. reformulation or redesign of products,
      3. substitution of materials, and
      4. improvement in management, inventory control, materials handling or general operational phases of the facility.
   e. Risk identification and assessment.
   f. Reporting of Plan incidents.
   g. Materials compatibility.
   h. Good housekeeping.
   i. Preventative maintenance.
   j. Inspections and records.
   k. Security.
   l. Employee training. The Plan shall identify periodic dates for training.
4. The Plan shall contain a written statement from corporate or facility management indicating management's commitment to the goals of the Plan program. The statement shall be publicized or made known to all facility employees. Management shall also provide training the individuals responsible for implementing the Plan.
5. The Plan shall be developed and implemented in accordance with the schedule contained in Part VI of this permit.

6. The Plan shall be signed by the permittee or their duly authorized representative in accordance with paragraphs 62-620.305(2)(a) and (b), F.A.C. The Plan shall be reviewed by appropriate facility staff and management. Where required by Chapter 471 (P.E.) or Chapter 492 (P.G.) F.S., applicable portions of the Plan shall be signed and sealed by the professional(s) who prepared them.

7. The permittee shall amend the Plan whenever there is a change in the facility or in the operation of the facility which materially increases the generation of pollutants or their release or potential release to industrial wastewater or stormwater. The permittee shall also amend the Plan, as appropriate, when plant operations covered by the Plan change. Any such changes to the Plan shall be consistent with the objectives and specific requirements listed below. All changes in the Plan shall be reported to the Department in writing.

8. At any time, if the Plan proves to be ineffective in achieving the general objective of preventing and minimizing the generation of pollutants and their release and potential release to industrial wastewater and stormwater or the specific requirements listed below, this permit or the Plan shall incorporate revised Plan requirements.

9. Progress/update reports documenting schedules and implementation of the Plan shall be maintained at the facility. The reports shall discuss whether implementation schedules were met and revise any schedules, as necessary. The Plan shall also be updated as necessary and the attainment or progress made toward specific pollutant reduction targets documented. Results of completed waste minimization assessment (WMA) studies shall be discussed. Results of any ongoing WMA studies, as well as any additional schedules for implementation of waste reduction practices, shall be included.

10. The permittee shall maintain the Plan, Progress/Update Reports, and other documents associated with the Plan at the facility and shall make these documents available to the Department upon request. All offices of the permittee which are required to maintain a copy of this NPDES permit shall also maintain a copy of the Plan.

11. The Department may notify the permittee at any time that the Plan does not meet one or more of the minimum requirements of this Part. Such notification shall identify those provisions of this permit which are not being met by the Plan, and identify which provisions of the Plan require~~s~~ modification~~s~~ in order to meet the minimum requirements of the Plan. Upon such notification, the permittee shall amend the Plan and shall submit to the Department a written certification that the requested changes have been made. Unless otherwise provided by the Department, the permittee shall have 30 days after such notification to make the changes necessary.

B. Industrial Wastewater Best Management Practices

1. The permittee shall develop and amend, as needed, the Plan consistent with the following objectives for the control of pollutants:

   a. The number and quantity of pollutants and the toxicity of effluent generated, discharged or potentially discharged at the facility shall be minimized by the permittee to the extent feasible by managing each influent waste stream in the most appropriate manner.

   b. Under the Plan, and any SOPs included in the Plan, the permittee shall ensure proper operation and maintenance of the treatment facility.

   c. The permittee shall establish specific objectives for the control of pollutants by conducting the following evaluations:
      (1) Each facility component or system shall be examined for its waste minimization opportunities and its potential for causing a release of amounts of pollutants to industrial wastewater and stormwater due to equipment failure, improper operation, and natural phenomena such as rain or adverse weather, etc. The examination shall include all normal operations and ancillary activities including but not limited to material storage areas, plant site runoff, in-plant transfer, process and material handling areas, loading or unloading operations, spillage or leaks, sludge and waste disposal, and drainage from raw material storage, as applicable.

      (2) Where experience indicates a reasonable potential for equipment failure (e.g., a tank overflow or leakage), natural condition (e.g., precipitation), or other circumstances to result in amounts of pollutants reaching surface waters, the program should include a prediction of the direction, rate of

flow and total quantity of pollutants which could be discharged from the facility as a result of each condition or circumstance.

2. The Industrial Wastewater BMPs component of the Plan shall include, at a minimum, the following items:

   a. A WMA for this facility to determine actions that could be taken to reduce waste loadings and chemical losses to all wastewater and/or stormwater streams as described Part VII.B.3, Required Components of a WMA, of this permit. It shall address both short-term and long-term opportunities for minimizing waste generation at this facility, utilizing at a minimum, applicable criteria selected from Part VII.B.3, particularly for high volume and/or high toxicity components of wastewater and stormwater streams. Initially, the WMA should focus primarily on actions that could be implemented quickly, thereby realizing tangible benefits to surface water quality. Long term goals and actions pertaining to waste reduction shall include investigation of the feasibility of eliminating toxic chemical use, instituting process changes, raw material replacements, etc.

      The permittee shall implement each waste reduction practice recommended by the WMA as soon as practicable. Any waste reduction practices which are identified but will not be implemented shall be described in the required progress/update reports, along with the factors inhibiting their adoption. Any waste reduction practices which cannot be implemented immediately shall be described in the Plan and included in a schedule of implementation.

      The permit issuing authority does not herein establish a time limit for completion of the WMA; the study may be conducted throughout the term of this permit. However, a suggested target completion date is six months after the effective date of this permit, so that the WMA results and recommended waste reduction practices may be incorporated into the Plan. Continual studies toward minimizing waste are encouraged.

      Practices which reduce pollutant loading in wastewater or stormwater discharges with a consequent increase in solid hazardous waste generation, decrease in air quality, or adverse effect to groundwater shall not be considered waste reduction for the purposes of this assessment.

   b. Specific BMPs to meet the objectives identified in Part VII.B.1 of this section, addressing each component or system capable of generating or causing a release of amounts of pollutants, and identifying specific preventative or remedial measures to be implemented.

3. Required Components of a WMA

   a. The WMA shall include an overall plant water balance, as well as internal water balances, as necessary. This information shall be used to determine any opportunities for water conservation or reuse/recycling and to determine if and where leakages might occur.

   b. A materials and risk assessment shall be developed and shall include the following:
      1. Identification of the types and quantities of materials used or manufactured (including by products produced) at the facility;
      2. Identification of the location and types of materials management activities which occur at the facility;
      3. An evaluation of the following aspects of materials compatibility: containment and storage practices for chemicals, container compatibility, chemical mixing procedures; potential mixing or compatibility problems; and specific prohibitions regarding mixing of chemicals;
      4. Technical information on human health and ecological effects of toxic or hazardous chemicals presently used or manufactured (including by products produced) or planned for future use or production; and
      5. Analyses of chemical use and waste generation, including overall plant material balances and as necessary, internal process balances, for all pollutants. (When actual measurements of the quantity of a chemical entering a wastewater or stormwater stream are not readily available, reasonable estimates should be made based on best engineering judgment.) The analyses shall address reasons for using particular chemicals, and measures or estimates of the actual and potential chemical discharges via wastewater, wastewater sludge, stormwater, air, solid waste or hazardous waste media.

   c. The WMA shall include, at a minimum, the following means of reducing pollutant discharges in wastewater streams or of otherwise minimizing wastes:

(1) Process related source reduction measures, including any or all of the following, as appropriate:
  (a) Production process changes;
  (b) Improved process controls;
  (c) Reduction of off specification materials;
  (d) Reduction in use of toxic or hazardous materials;
  (e) Chemical modifications and/or material purification;
  (f) Chemical substitution employing non-toxic or less toxic alternatives;
  (g) Equipment upgrades or modifications or changes in equipment use; and
  (h) Implementation of the Turkey Point CCS Nutrient Management Plan (September 16, 2016), including annual reporting on progress.
(2) Housekeeping/operational changes, including waste stream segregation, inventory control, spill and leak prevention, equipment maintenance; and employee training in areas of material management and pollution prevention, good housekeeping, and spill prevention and response;
(3) In process recycling, on-site recycling and/or off-site recycling of materials;
(4) Following all source reduction and recycling practices, wastewater treatment process changes, including the use of new or improved treatment methods, such that treatment by products are less toxic to aquatic or human life; and
(5) Other means as agreed upon by the permit issuing authority and the permittee.

d. For stormwater discharges and instances where stormwater enters the wastewater treatment/disposal system or is otherwise commingled with wastewater, the WMA shall evaluate the following potential sources of stormwater contamination, at a minimum:
(1) Loading, unloading and transfer areas for dry bulk materials or liquids;
(2) Outdoor storage of raw materials or products;
(3) Outdoor manufacturing or processing activities;
(4) Dust or particulate generating processes; and
(5) On-site waste and/or sludge disposal practices.

The likelihood of stormwater contact in these areas and the potential for spills from these areas shall be considered in the evaluation. The history of leaks or spills of toxic or hazardous pollutants shall also be considered. Recommendations for changes to current practices which would reduce the potential for stormwater contamination from these areas shall be made, as necessary.

C. Stormwater Best Management Practices

1. Stormwater BMPs components of the Plan shall include, at a minimum, the following items:

a. A description of potential sources which may reasonably be expected to add pollutants to stormwater discharges from separate stormwater conveyances at the facility. The Plan shall identify all activities and materials that may potentially be pollutant sources. The Plan shall include, at a minimum:

(1) Drainage
  (a) A site map indicating an outline of the portions of the drainage area of each stormwater outfall that are within the facility boundaries, each existing structural control measure to reduce pollutants in stormwater runoff, surface water bodies, locations where materials are exposed to precipitation, locations where spills or leaks identified under Item VII.C.1.a.(3) have occurred, and the locations of the following activities where such activities are exposed to precipitation: fueling stations; vehicle and equipment maintenance and/or cleaning areas; loading/unloading areas; locations used for the treatment, storage or disposal of wastes; liquid storage tanks; processing areas; and storage areas.
  (b) For each area of the facility that generates stormwater discharges associated with industrial activity with a reasonable potential for containing pollutants, a prediction of the direction of flow, and an identification of the types of pollutants which are likely to be present in stormwater discharges associated with industrial activity. Factors to consider include the toxicity of chemical; quantity of chemicals used, produced or discharged; the likelihood of contact with stormwater; and

history of leaks or spills of toxic or hazardous pollutants. Flows with a potential for causing erosion shall be identified.

(2) An inventory of the types of materials handled at the site that potentially may be exposed to precipitation. Such inventory shall include a narrative description of materials that have been handled, treated, stored or disposed in a manner to allow exposure to stormwater between the time of three years prior to the effective date of this permit and the present; method and location of on-site storage or disposal; materials management practices employed to minimize contact of materials with stormwater runoff between the time of three years prior to the effective date of this permit and the present; the location and a description of existing structural and non-structural control measures to reduce pollutants in stormwater runoff; and a description of any treatment the stormwater receives.

(3) A list of spills and leaks of toxic or hazardous pollutants that occurred at areas that are exposed to precipitation or that otherwise drain to a stormwater conveyance at the facility after the date of three years prior to the effective date of this permit. Such a list shall be updated as appropriate during the term of this permit.

(4) A summary of existing discharge sampling data describing pollutants in stormwater discharges from the facility, including a summary of sampling data collected during the term of this permit.

(5) A narrative description of the potential pollutant sources from the following activities if applicable: loading and unloading operations; outdoor storage activities; outdoor manufacturing or processing activities; dust or particulate generating processes; loading/unloading areas; and on-site waste disposal practices. The description shall specifically list any potential source of pollutants at the site and for each potential source, any pollutant or pollutant parameter (e.g. biochemical oxygen demand, etc.) of concern shall be identified.

b. A description of stormwater management controls appropriate for the facility and implement such controls. The appropriateness and priorities of controls in the Plan shall reflect identified potential sources of pollutants at the facility. The description of stormwater management controls shall address the following minimum components, including a schedule for implementing such controls:

(1) Good housekeeping requires the maintenance of areas that may contribute pollutants to stormwater discharges in a clean, orderly manner.

(2) A preventive maintenance program shall involve timely inspection and maintenance of stormwater management devices (e.g. cleaning oil/water separators, catch basins) as well as inspecting and testing facility equipment and systems to uncover conditions that could cause breakdowns or failures resulting in discharges of pollutants to surface waters, and ensuring appropriate maintenance of such equipment and systems.

(3) Areas where potential spills that can contribute pollutants to stormwater discharges can occur and their accompanying drainage points shall be identified clearly in the Plan. Where appropriate, specifying material handling procedures, storage requirements, and use of equipment such as diversion valves in the Plan should be considered. Procedures for cleaning up spills shall be identified in the Plan and made available to the appropriate personnel. The necessary equipment to implement a cleanup should be available to personnel.

(4) In addition to or as part of the comprehensive site evaluation required under paragraph VII.C.1.c of this section, qualified facility personnel shall be identified to inspect designated equipment and areas of the facility at appropriate intervals specified in the Plan. A set of tracking or follow-up procedures shall be used to ensure that appropriate actions are taken in response to the inspections. Records of inspections shall be maintained.

(5) Employee training programs shall inform personnel responsible for implementing activities identified in the Plan or otherwise responsible for stormwater management at all levels of responsibility of the components and goals of the Plan. Training should address topics such material management and pollution prevention, good housekeeping and spill prevention and response. The Plan shall identify periodic dates for such training.

(6) A description of incidents (such as spills, or other discharges), along with other information describing the quality and quantity of stormwater discharges shall be included in the Plan required under this part.

Inspections and maintenance activities shall be documented and records of such activities shall be incorporated into the Plan.

(7) Non-Stormwater Discharges

(a) The Plan shall include a certification that each "stormwater-only" discharge authorized under this permit has been tested or evaluated for the presence of non-stormwater discharges. (This section is not applicable to those discharges authorized under this permit that have been identified in the application as having non-stormwater components.) The certification shall include the identification of potential sources of non-stormwater at the site, a description of the results of any test and/or evaluation for the presence of non-stormwater discharges, the evaluation criteria or testing method used, the date of any testing and/or evaluation, and the on-site drainage points that were directly observed during the test. Such certification may not be feasible if the facility operating the stormwater discharge associated with industrial activity does not have access to an outfall, manhole, or other point of access to the ultimate conduit that receives the discharge. In such cases, the source identification section of the Plan shall indicate why the certification required by this part was not feasible, along with the identification of potential sources of non-stormwater at the site. A discharger that is unable to provide the certification required by this paragraph must notify the Department in accordance with paragraph VII.C.1.b.(7)(c) below.

(b) Except for flows from fire-fighting activities, sources of authorized non-stormwater discharges that are combined with stormwater discharges associated with industrial activity must be identified in the Plan. The Plan shall identify and ensure the implementation of appropriate pollution prevention measures for the non-stormwater component(s) of the discharge.

(c) Failure to Certify. Any facility that is unable to provide the certification required (testing for non-stormwater discharges), must notify the Department. If the failure to certify is caused by the inability to perform adequate tests or evaluations, such notification shall describe: the procedure of any test conducted for the presence of non-stormwater discharges; the results of such test or other relevant observations; potential sources of non-stormwater discharges to the storm sewer; and why adequate tests for such storm sewers were not feasible. Non-stormwater discharges to surface waters of the State which are not authorized by an NPDES permit are unlawful, and must be terminated or dischargers must submit appropriate NPDES permit application forms.

(8) The Plan shall identify areas which, due to topography, activities, or other factors, have a high potential for soil erosion, and identify structural, vegetative, and/or stabilization measures to be used to limit erosion.

(9) The Plan shall contain a narrative consideration of the appropriateness of traditional stormwater management practices (practices other than those which control the generation or source(s) of pollutants) used to divert, infiltrate, reuse, or otherwise manage stormwater runoff in a manner that reduces pollutants in stormwater discharges from the site. The Plan shall provide that those measures that the permittee determines to be reasonable and appropriate shall be implemented and maintained. The potential of various sources at the facility to contribute pollutants to stormwater discharges associated with industrial activity shall be considered when determining reasonable and appropriate measures. Appropriate measures may include: vegetative swales and practices; reuse of collected stormwater (such as for a process or as an irrigation source); inlet controls (such as oil/water separators); infiltration devices; and, detention or retention devices.

c. A Comprehensive Site Compliance Evaluation. Qualified personnel shall conduct site compliance evaluations at appropriate intervals specified in the Plan, but in no case less than once a year. Such evaluations shall provide:

(1) Areas contributing to a stormwater discharge associated with industrial activity shall be visually inspected for evidence of, or the potential for, pollutants entering the drainage system. Measures to reduce pollutant loadings shall be evaluated to determine whether they are adequate and properly implemented in accordance with the terms of this permit or whether additional control measures are needed. Structural stormwater management measures, sediment and erosion control measures, and other structural pollution prevention measures identified in the Plan shall be observed to ensure that they are operating correctly. A visual inspection of equipment needed to implement the Plan, such as spill response equipment, shall be made.

(2) Based on the results of the inspection, the description of potential pollutant sources identified in the Plan in accordance with paragraph VII.C.1.a.(5) of this section and pollution prevention measures and

controls identified in the Plan in accordance with paragraph VII.C.1.b of this section shall be revised as appropriate within two weeks of such inspection and shall provide for implementation of any changes to the Plan in a timely manner, but in no case more than twelve weeks after the inspection.

(3) A report summarizing the scope of the inspection, personnel making the inspection, the date(s) of the inspection, observations relating to the implementation of the Plan and actions taken shall be made and retained as part of the Plan. The report shall identify any incidents of non-compliance, and corrective actions taken. Where a report does not identify any incidents of non-compliance, the report shall contain a certification that the facility is in compliance with the Plan and this permit. The report shall be signed in accordance with paragraph VII.A.6 of this section.

d. Consistency with other plans. The Plan may reference the existence of other plans for Spill Prevention Control and Countermeasure (SPCC), plans developed for the facility under section 311 of the CWA or BMP Programs otherwise required by an NPDES permit for the facility if such requirement is incorporated into the Plan.

VIII. OTHER SPECIFIC CONDITIONS

A. Specific Conditions Applicable to All Permits

1. Where required by Chapter 471 (P.E.) or Chapter 492 (P.G.), F.S., applicable portions of reports that must be submitted under this permit shall be signed and sealed by a State-registered professional engineer or professional geologist, as appropriate. *[62-620.310(4)]*

2. Drawings, plans, documents or specifications submitted by the permittee, not attached hereto, but retained on file at the Department's Wastewater Management Program in Tallahassee, are made a part hereof.

3. This permit satisfies Wastewater Management Program permitting requirements only and does not authorize operation of this facility prior to obtaining any other permits required by local, state or federal agencies.

B. Specific Conditions Related to Existing Manufacturing, Commercial, Mining, and Silviculture Wastewater Facilities or Activities

1. Existing manufacturing, commercial, mining, and silvicultural wastewater facilities or activities that discharge into surface waters shall notify the Department as soon as they know or have reason to believe:

   a. That any activity has occurred or will occur which would result in the discharge, on a routine or frequent basis, of any toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the following levels;
   (1) One hundred micrograms per liter,
   (2) Two hundred micrograms per liter for acrolein and acrylonitrile; five hundred micrograms per liter for 2, 4-dinitrophenol and for 2-methyl-4, 6-dinitrophenol; and one milligram per liter for antimony, or
   (3) Five times the maximum concentration value reported for that pollutant in the permit application; or

   b. That any activity has occurred or will occur which would result in any discharge, on a non-routine or infrequent basis, of a toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the following levels;
   (1) Five hundred micrograms per liter,
   (2) One milligram per liter for antimony, or
   (3) Ten times the maximum concentration value reported for that pollutant in the permit application.

   [62-620.625(1)]

C. Duty to Reapply

1. The permittee is not authorized to release wastewater into the CCS after the expiration date of this permit, unless:

   a. the permittee has applied for renewal of this permit at least 180 days before the expiration date (**Month, Day, Year**) using the appropriate forms listed in Rule 62-620.910, F.A.C., and in the manner established in the Department of Environmental Protection Guide to Permitting Wastewater Facilities or Activities Under Chapter 62-620, F.A.C., including submittal of the appropriate processing fee set forth in Rule 62-4.050, F.A.C.; or

b. the permittee has made complete the application for renewal of this permit before the permit expiration date.

[62-620.335(1)-(4)]

2. When publishing Notice of Draft and Notice of Intent in accordance with Rules 62-110.106 and 62-620.550, F.A.C., the permittee shall publish the notice at its expense in a newspaper of general circulation in the county or counties in which the activity is to take place either

   a. Within thirty days after the permittee has received a notice; or

   b. Within thirty days after final agency action.

   Failure to publish a notice is a violation of this permit.

D. Reopener Clauses

1. The permit shall be revised, or alternatively, revoked and reissued in accordance with the provisions contained in Rules 62-620.325 and 62-620.345 F.A.C., if applicable, or to comply with any applicable effluent standard or limitation issued or approved under Sections 301(b)(2)(C) and (D), 304(b)(2) and 307(a)(2) of the CWA, as amended, if the effluent standards, limitations, or water quality standards so issued or approved:

   a. Contains different conditions or is otherwise more stringent than any condition in the permit/or;

   b. Controls any pollutant not addressed in the permit.

   The permit as revised or reissued under this paragraph shall contain any other requirements then applicable.

2. The permit may be reopened to adjust effluent limitations or monitoring requirements should future Water Quality Based Effluent Limitation determinations, water quality studies, Department approved changes in water quality standards, EPA established Total Maximum Daily Loads (TMDLs), or other information show a need for a different limitation, monitoring requirement, or more stringent requirements.

3. The Department or EPA may develop a TMDL during the life of the permit. Once a TMDL has been established and adopted by rule, the Department shall revise this permit to incorporate the final findings of the TMDL.

4. The permittee and the Department entered into a Consent Order (OGC File #16-0241) on June 20, 2016. The Department may revise the permit to include certain provisions of the Consent Order upon its completion.

E. Impoundment Design, Construction, Operation, and Maintenance

1. All impoundments used to hold or treat wastewater and stormwater, including the CCS, shall be designed, constructed, operated, and maintained to prevent the discharge of pollutants to waters of the State, except as authorized under this permit.

2. Design, construction, operation, and maintenance of any impoundment shall be in accordance with all relevant State and Federal regulations and shall be certified by a qualified, State-registered professional engineer and permitted and inspected by the appropriate agency prior to use. When practicable, piezometers or other instrumentation shall be installed as a means to aid monitoring of impoundment integrity.

3. In addition to other regular maintenance activities conduction for the CCS, which for the purposes of this section is considered an impoundment, the perimeter berms and slopes shall be maintained to protect the structural

integrity. This may include removal of trees greater than 4 inches in diameter. Vegetation and materials shall be handled and managed in accordance to the Best Management Practices Plan in Section VII of this permit.

F. Impoundment Inspections

1. The CCS periphery including the three small dams (Hotel 2, Turtle Point Canal, and the Cellular Cofferdam) shall be inspected above and below the surface waterline for the entire perimeter at a minimum of once every five years by an independent qualified, State-registered professional engineer. The three dams and all other aspects of the perimeter impoundments shall be inspected annually by a qualified, State-registered professional engineer. The term qualified means having successfully completed the Mine Safety and Health Administration Qualification for Impoundment Inspection course in addition to the Annual Retraining for Impoundment Qualification, or equivalent Qualifications. Additional inspections by qualified personnel shall be done within 7 days after large or extended rain events (i.e., 10-year, 24-hour precipitation event).

2. Inspections shall, at a minimum, include observations of dams, including the three dams (Hotel 2, Turtle Point Canal and the Cellular Cofferdam) of the CCS, dikes and toe areas for erosion, corrosion, cracks or bulges, seepage, wet or soft soil, changes in geometry, the depth and elevation of the impounded water, sediment or slurry, freeboard, changes in vegetation such as overly lush, dead or unnaturally tilted vegetation, and any other changes which may indicate a potential compromise to impoundment integrity.

   To monitor function of the cathodic protection system, suggested operation and maintenance practices described in the Operation and Maintenance Manual accompanying these devices shall be followed.

   In addition, the CCS shall be monitored in the months of April and August of each year to determine its thermal efficiency. The thermal efficiency in the CCS shall be calculated as described in the Turkey Point Cooling Canal System Thermal Efficiency Plan. If the permittee fails to achieve a minimum annual average of 70 percent, the permittee shall, within 30 days of discovering that the thermal efficiency is below the threshold, commence actions prescribed in the Turkey Point Cooling Canal System Thermal Efficiency Plan. If the permittee fails to reach the threshold by the following annual report, within 30 days, the permittee shall notify the Tallahassee Wastewater Management Program of additional measures to be taken, and a timeframe for achieving the threshold. The Turkey Point Cooling Canal System Thermal Efficiency Plan shall be updated to include the additional measures.

   The findings of each inspection including thermal efficiency, shall be documented in a written annual inspection report as described in permit condition VIII.G.1 below.

3. Remediation Measures. Within 24 hours of discovering changes that indicate a potential compromise to the structural integrity or the efficient operation of the CCS, the permittee shall begin procedures to remediate the problem. Adherence to the six components of the Turkey Point Cooling Canal System Thermal Efficiency Plan dated December 14, 2016, shall be incorporated into the facility's best management practices.

4. Within 5 days of discovering any changes in the CCS that indicate a potential compromise to the structural integrity or operation, the permittee must notify the Department in writing describing the findings of the inspection, corrective measures taken since discovery of the change, other planned corrective measures and the expected outcomes. Failure to do so will be a violation of this permit.

5. Other issues which may have long term impacts on impoundment integrity, such as trees growing on the CCS perimeter impoundment or banks or vegetation blocking canals or spillways, shall be cleared within a timely manner to ensure operational integrity, but no later than 6 months from first observation. In addition, the CCS impoundment shall be maintained to prevent the growth, accumulation, or spread of any plant species.

6. During routine operational and maintenance activities around the CCS, periodic observation of the perimeter should continue reporting noted defects.

G. Reporting and Recordkeeping Requirements

1. In accordance with schedule item VI.4 the permittee shall submit an annual report of all impoundment inspections and maintenance activities, including corrective actions made in response to inspections, summarizing findings of all monitoring activities including the annual thermal efficiency evaluation of the CCS, remediation measures pertaining to the structural integrity, design, construction, and operation and maintenance of the CCS, and all other activities undertaken to repair or maintain the CCS and other impoundments.

2. In accordance with Section 403.077, F.S., unauthorized releases or spills reportable to the StateWatch Office pursuant to permit condition IX.20 shall also be reported to the Department within 24 hours from the time the permittee becomes aware of the discharge. The permittee shall provide to the Department information reported to the State Watch Office. Notice of unauthorized releases or spills may be provided to the Department through the Department's Public Notice of Pollution web page at https://floridadep.gov/pollutionnotice.

    a. If, after providing notice pursuant to paragraph (2) above, the permittee determines that a reportable unauthorized release or spill did not occur or that an amendment to the notice is warranted, the permittee may submit a letter to the Department documenting such determination.

    b. If, after providing notice pursuant to paragraph (2) above, the permittee discovers that a reportable unauthorized release or spill has migrated outside the property boundaries of the installation, the permittee must provide an additional notice to the Department that the release has migrated outside the property boundaries within 24 hours after its discovery of the migration outside of the property boundaries.

H. Specific Conditions Related to Preservation of State Historical Resources

1. If prehistoric or historic artifacts, such as pottery or ceramics, projectile points, dugout canoes, metal implements, historic building materials, or any other physical remains that could be associated with Native American, early European, or American settlement are discovered at any time within the project site area, the permittee shall immediately notify the Florida Department of State, Division of Historical Resources, Compliance Review Section at (850) 245-6333, to determine appropriate action.

2. In the event that unmarked human remains are encountered during permitted activities, all work shall stop immediately and the proper authorities notified in accordance with Section 872.05, Florida Statutes.

I. Other Noncompliance Reporting Requirements

1. In accordance with Section 403.077, F.S., unauthorized releases or spills reportable to the State Watch Office pursuant to Permit Condition IX.20.b.1. shall also be reported to the Department within 24 hours from the time the permittee becomes aware of the discharge. The permittee shall provide to the Department information reported to the State Watch Office. Notice of unauthorized releases or spills may be provided to the Department through the Department's Public Notice of Pollution web page at https://floridadep.gov/pollutionnotice.

    a. If, after providing notice pursuant to paragraph 1 above, the permittee determines that a reportable unauthorized release or spill did not occur or that an amendment to the notice is warranted, the permittee may submit additional notice to the Department documenting such determination.
    b. If, after providing notice pursuant to paragraph 1 above, the permittee discovers that a reportable unauthorized release or spill has migrated outside the property boundaries of the installation, the permittee must provide an additional notice to the Department that the release has migrated outside the property boundaries within 24 hours after its discovery of the migration outside of the property boundaries.

    [62-620.100(3)] [403.077, F.S.]

IX. GENERAL CONDITIONS

1. The terms, conditions, requirements, limitations and restrictions set forth in this permit are binding and enforceable pursuant to Chapter 403, Florida Statutes. Any permit noncompliance constitutes a violation of Chapter 403, Florida Statutes, and is grounds for enforcement action, permit termination, permit revocation and reissuance, or permit revision. *[62-620.610(1)]*

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviations from the approved drawings, exhibits, specifications or conditions of this permit constitutes grounds for revocation and enforcement action by the Department. *[62-620.610(2)]*

3. As provided in Section 403.087(7), F.S., the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor authorize any infringement of federal, state, or local laws or regulations. This permit is not a waiver of or approval of any other Department permit or authorization that may be required for other aspects of the total project which are not addressed in this permit. *[62-620.610(3)]*

4. This permit conveys no title to land or water, does not constitute state recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title. *[62-620.610(4)]*

5. This permit does not relieve the permittee from liability and penalties for harm or injury to human health or welfare, animal or plant life, or property caused by the construction or operation of this permitted source; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department. The permittee shall take all reasonable steps to minimize or prevent any discharge, reuse of reclaimed water, or residuals use or disposal in violation of this permit which has a reasonable likelihood of adversely affecting human health or the environment. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. *[62-620.610(5)]*

6. If the permittee plans to continue an activity regulated by this permit after its expiration date, the permittee shall apply for and obtain a new permit. *[62-620.610(6)]*

7. The permittee shall at all times properly operate and maintain the facility and systems of treatment and control, and related appurtenances, that are installed and used by the permittee to achieve compliance with the conditions of this permit. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to maintain or achieve compliance with the conditions of the permit. *[62-620.610(7)]*

8. This permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the permittee for a permit revision, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance does not stay any permit condition. *[62-620.610(8)]*

9. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, including an authorized representative of the Department and authorized EPA personnel, when applicable, upon presentation of credentials or other documents as may be required by law, and at reasonable times, depending upon the nature of the concern being investigated, to:

    a. Enter upon the permittee's premises where a regulated facility, system, or activity is located or conducted, or where records shall be kept under the conditions of this permit;

    b. Have access to and copy any records that shall be kept under the conditions of this permit;

    c. Inspect the facilities, equipment, practices, or operations regulated or required under this permit; and

    d. Sample or monitor any substances or parameters at any location necessary to assure compliance with this permit or Department rules.

    [62-620.610(9)]

10. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data, and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except as such use is proscribed by Section 403.111, F.S., or Rule 62-

620.302, F.A.C. Such evidence shall only be used to the extent that it is consistent with the Florida Rules of Civil Procedure and applicable evidentiary rules. *[62-620.610(10)]*

11. When requested by the Department, the permittee shall within a reasonable time provide any information required by law which is needed to determine whether there is cause for revising, revoking and reissuing, or terminating this permit, or to determine compliance with the permit. The permittee shall also provide to the Department upon request copies of records required by this permit to be kept. If the permittee becomes aware of relevant facts that were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be promptly submitted or corrections promptly reported to the Department. *[62-620.610(11)]*

12. Unless specifically stated otherwise in Department rules, the permittee, in accepting this permit, agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance; provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules. A reasonable time for compliance with a new or amended surface water quality standard, other than those standards addressed in Rule 62-302.500, F.A.C., shall include a reasonable time to obtain or be denied a mixing zone for the new or amended standard. *[62-620.610(12)]*

13. The permittee, in accepting this permit, agrees to pay the applicable regulatory program and surveillance fee in accordance with Rule 62-4.052, F.A.C. *[62-620.610(13)]*

14. This permit is transferable only upon Department approval in accordance with Rule 62-620.340, F.A.C. The permittee shall be liable for any noncompliance of the permitted activity until the transfer is approved by the Department. *[62-620.610(14)]*

15. The permittee shall give the Department written notice at least 60 days before inactivation or abandonment of a wastewater facility or activity and shall specify what steps will be taken to safeguard public health and safety during and following inactivation or abandonment. *[62-620.610(15)]*

16. The permittee shall apply for a revision to the Department permit in accordance with Rule 62-620.300, F.A.C., and the Department of Environmental Protection Guide to Permitting Wastewater Facilities or Activities Under Chapter 62-620, F.A.C., at least 90 days before construction of any planned substantial modifications to the permitted facility is to commence or with subsection 62-620.325(2), F.A.C., for minor modifications to the permitted facility. A revised permit shall be obtained before construction begins except as provided in Rule 62-620.300, F.A.C. *[62-620.610(16)]*

17. The permittee shall give advance notice to the Department of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements. The permittee shall be responsible for any and all damages which may result from the changes and may be subject to enforcement action by the Department for penalties or revocation of this permit. The notice shall include the following information:

    a. A description of the anticipated noncompliance;

    b. The period of the anticipated noncompliance, including dates and times; and

    c. Steps being taken to prevent future occurrence of the noncompliance.

    [62-620.610(17)]

18. Sampling and monitoring data shall be collected and analyzed in accordance with Rule 62-4.246 and Chapters 62-160, 62-601, and 62-610, F.A.C., and 40 CFR 136, as appropriate.

    a. Monitoring results shall be reported at the intervals specified elsewhere in this permit and shall be reported on a DMR, DEP Form 62-620.910(10), or as specified elsewhere in the permit.

    b. If the permittee monitors any contaminant more frequently than required by the permit, using Department approved test procedures, the results of this monitoring shall be included in the calculation and reporting of the data submitted in the DMR.

    c. Calculations for all limitations which require averaging of measurements shall use an arithmetic mean unless otherwise specified in this permit.

d. Except as specifically provided in Rule 62-160.300, F.A.C., any laboratory test required by this permit shall be performed by a laboratory that has been certified by the Department of Health Environmental Laboratory Certification Program (DOH ELCP). Such certification shall be for the matrix, test method and analyte(s) being measured to comply with this permit.

e. Field activities including on-site tests and sample collection shall follow the applicable standard operating procedures described in DEP-SOP-001/01 adopted by reference in Chapter 62-160, F.A.C.

f. Alternate field procedures and laboratory methods may be used where they have been approved in accordance with Rules 62-160.220, and 62-160.330, F.A.C.

[62-620.610(18)]

19. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule detailed elsewhere in this permit shall be submitted no later than 14 days following each schedule date. *[62-620.610(19)]*

20. The permittee shall report to the Department's Southeast District Office any noncompliance which may endanger health or the environment. Any information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided within five days of the time the permittee becomes aware of the circumstances. The written submission shall contain: a description of the noncompliance and its cause; the period of noncompliance including exact dates and time, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

a. The following shall be included as information which must be reported within 24 hours under this condition:
(1) Any unanticipated bypass which causes any reclaimed water or effluent to exceed any permit limitation or results in an unpermitted discharge,
(2) Any upset which causes any reclaimed water or the effluent to exceed any limitation in the permit,
(3) Violation of a maximum daily discharge limitation for any of the pollutants specifically listed in the permit for such notice, and
(4) Any unauthorized discharge to surface or groundwaters.

b. Oral reports as required by this subsection shall be provided as follows:
(1) For unauthorized releases or spills of treated or untreated wastewater reported pursuant to subparagraph 20(a).4. that are in excess of 1,000 gallons per incident, or where information indicates that public health or the environment will be endangered, oral reports shall be provided to the STATE WATCH POINT OFFICE TOLL FREE NUMBER (800) 320-0519, as soon as practical, but no later than 24 hours from the time the permittee becomes aware of the discharge. The permittee, to the extent known, shall provide the following information to the State Watch Point:
(a) Name, address, and telephone number of person reporting;
(b) Name, address, and telephone number of permittee or responsible person for the discharge;
(c) Date and time of the discharge and status of discharge (ongoing or ceased);
(d) Characteristics of the wastewater spilled or released (untreated or treated, industrial or domestic wastewater);
(e) Estimated amount of the discharge;
(f) Location or address of the discharge;
(g) Source and cause of the discharge;
(h) Whether the discharge was contained on-site, and cleanup actions taken to date;
(i) Description of area affected by the discharge, including name of water body affected, if any; and
(j) Other persons or agencies contacted.
(2) Oral reports, not otherwise required to be provided pursuant to subparagraph 20.b.1 above, shall be provided to the Department's Southeast District Office within 24 hours from the time the permittee becomes aware of the circumstances.

c. If the oral report has been received within 24 hours, the noncompliance has been corrected, and the noncompliance did not endanger health or the environment, the Department's Southeast District Office shall waive the written report.

[62-620.610(20)]

21. The permittee shall report all instances of noncompliance not reported under Permit Conditions IX. 17, 18 or 19 of this permit at the time monitoring reports are submitted. This report shall contain the same information required by Permit Condition IX.20 of this permit. *[62-620.610(21)]*

22. Bypass Provisions.

    a. "Bypass" means the intentional diversion of waste streams from any portion of a treatment works.

    b. Bypass is prohibited, and the Department may take enforcement action against a permittee for bypass, unless the permittee affirmatively demonstrates that:
       (1) Bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and
       (2) There were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime. This condition is not satisfied if adequate back-up equipment should have been installed in the exercise of reasonable engineering judgment to prevent a bypass which occurred during normal periods of equipment downtime or preventive maintenance; and
       (3) The permittee submitted notices as required under Permit Condition IX.22.c. of this permit.

    c. If the permittee knows in advance of the need for a bypass, it shall submit prior notice to the Department, if possible at least 10 days before the date of the bypass. The permittee shall submit notice of an unanticipated bypass within 24 hours of learning about the bypass as required in Permit Condition IX.20. of this permit. A notice shall include a description of the bypass and its cause; the period of the bypass, including exact dates and times; if the bypass has not been corrected, the anticipated time it is expected to continue; and the steps taken or planned to reduce, eliminate, and prevent recurrence of the bypass.

    d. The Department shall approve an anticipated bypass, after considering its adverse effect, if the permittee demonstrates that it will meet the three conditions listed in Permit Condition IX. 22.b.1 through 3 of this permit.

    e. A permittee may allow any bypass to occur which does not cause reclaimed water or effluent limitations to be exceeded if it is for essential maintenance to assure efficient operation. These bypasses are not subject to the provisions of Permit Condition IX.22.a. through c. of this permit.

    [62-620.610(22)]

23. Upset Provisions.

    a. "Upset" means an exceptional incident in which there is unintentional and temporary noncompliance with technology-based effluent limitations because of factors beyond the reasonable control of the permittee.
       (1) An upset does not include noncompliance caused by operational error, improperly designed treatment facilities, inadequate treatment facilities, lack of preventive maintenance, careless or improper operation.
       (2) An upset constitutes an affirmative defense to an action brought for noncompliance with technology based permit effluent limitations if the requirements of upset provisions of Rule 62-620.610, F.A.C., are met.

    b. A permittee who wishes to establish the affirmative defense of upset shall demonstrate, through properly signed contemporaneous operating logs, or other relevant evidence that:
       (1) An upset occurred and that the permittee can identify the cause(s) of the upset;
       (2) The permitted facility was at the time being properly operated;
       (3) The permittee submitted notice of the upset as required in Permit Condition IX.20. of this permit; and
       (4) The permittee complied with any remedial measures required under Permit Condition IX.20. of this permit.

    c. In any enforcement proceeding, the burden of proof for establishing the occurrence of an upset rests with the permittee.

    d. Before an enforcement proceeding is instituted, no representation made during the Department review of a claim that noncompliance was caused by an upset is final agency action subject to judicial review.

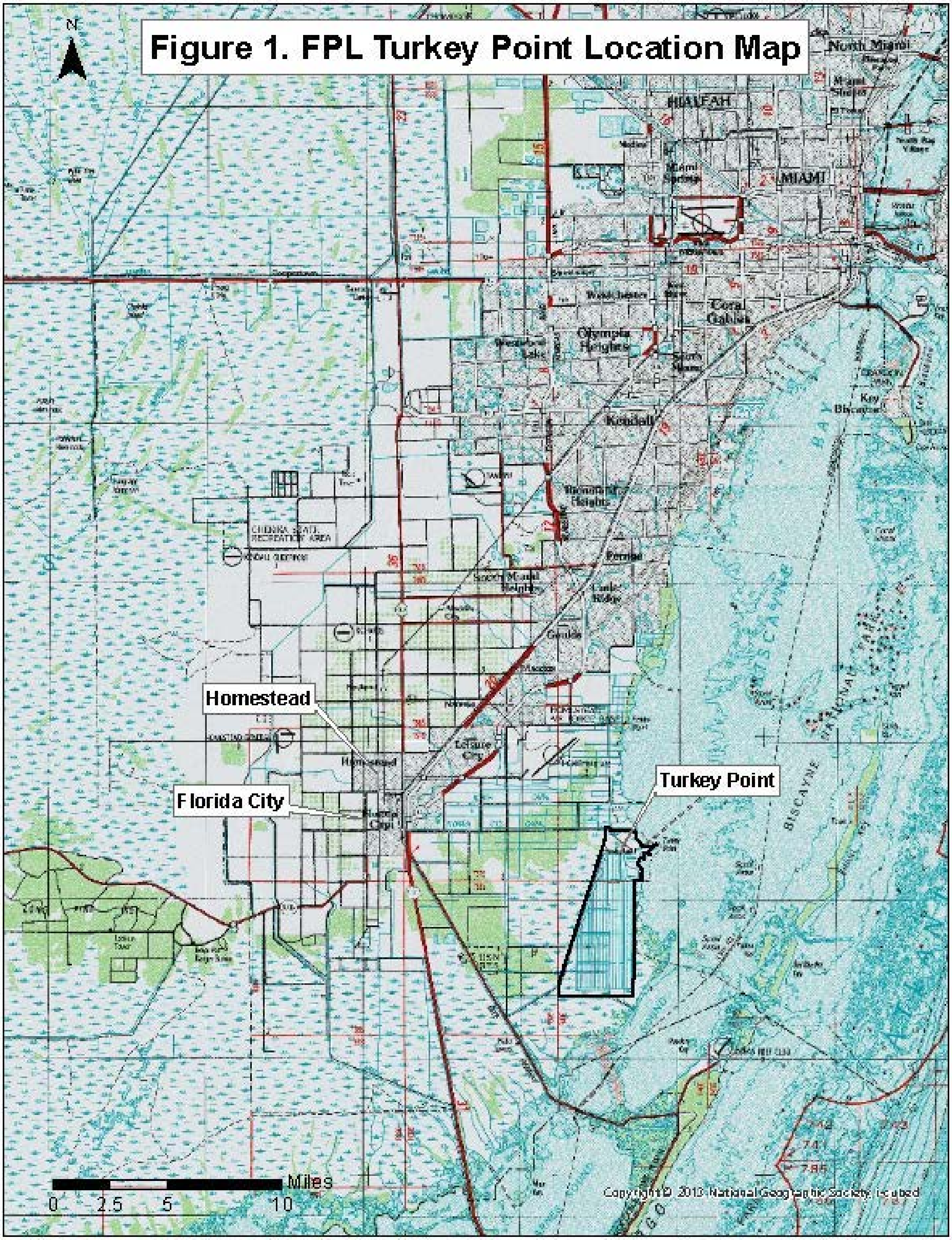
    [62-620.610(23)]

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENTOF
ENVIRONMENTAL PROTECTION

____
Benjamin M. Melnick
Director
Division of Water Resource Management

PERMITTEE:	Florida Power & Light Company (FPL)	PERMIT NUMBER:	FL0001562 (Major)
FACILITY:	Turkey Point Power Plant	EXPIRATION DATE:	



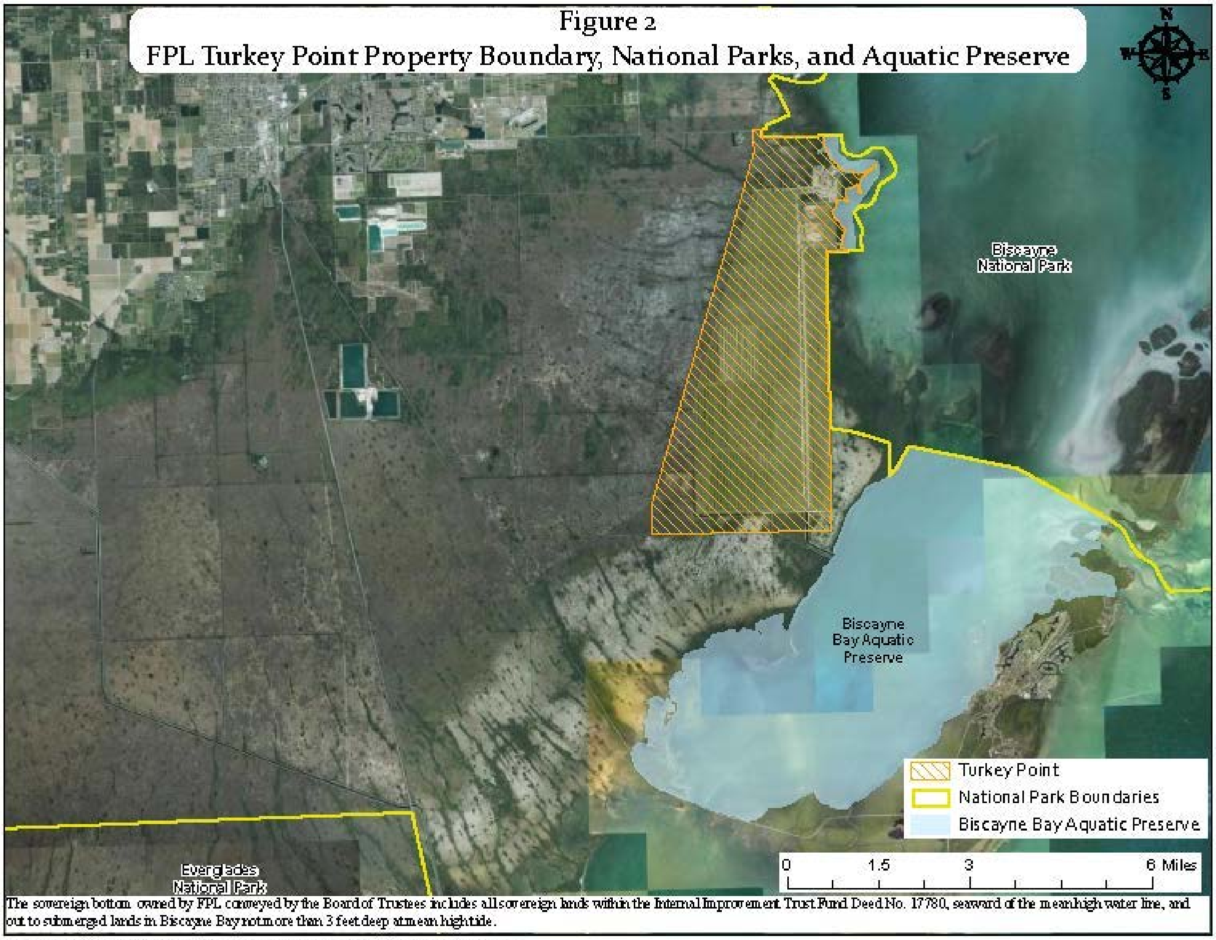


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Figure 3
FPL Turkey Point Property Boundary

Figure 4. FPL Turkey Point Power Plant Units 3 & 4 Flow Diagram

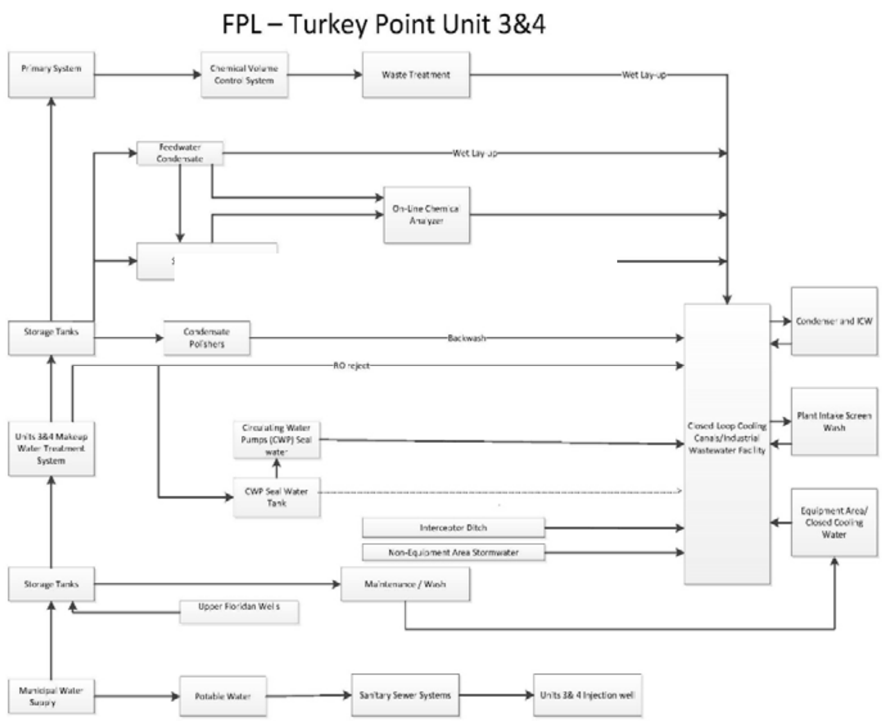

Figure 5. FPL Turkey Point Power Plant Unit 5 Flow Diagram

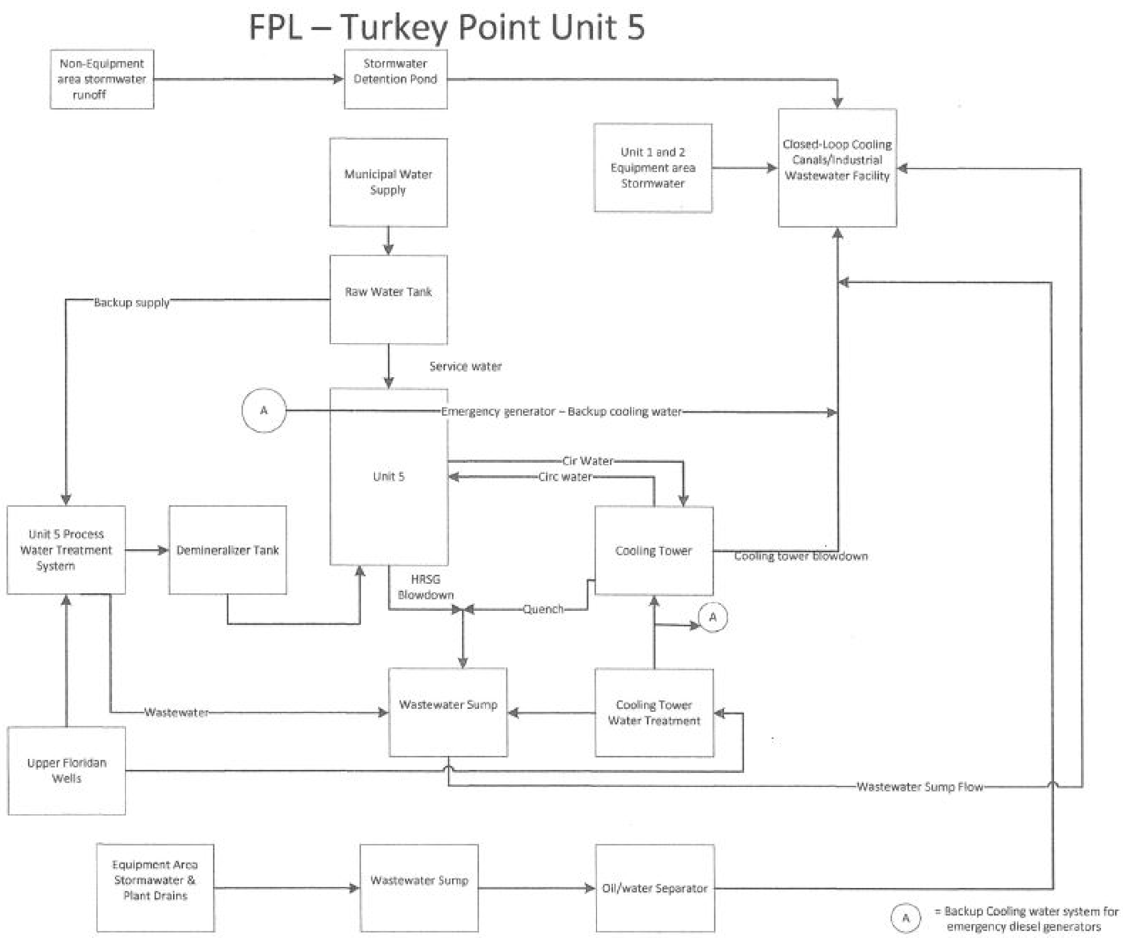

Figure 6. FPL Turkey Point Power Plant Groundwater, Surface Water, and Porewater Monitoring Locations

PERMITTEE:	Florida Power & Light Company (FPL)	PERMIT NUMBER:	FL0001562 (Major)
FACILITY:	Turkey Point Power Plant	EXPIRATION DATE:	

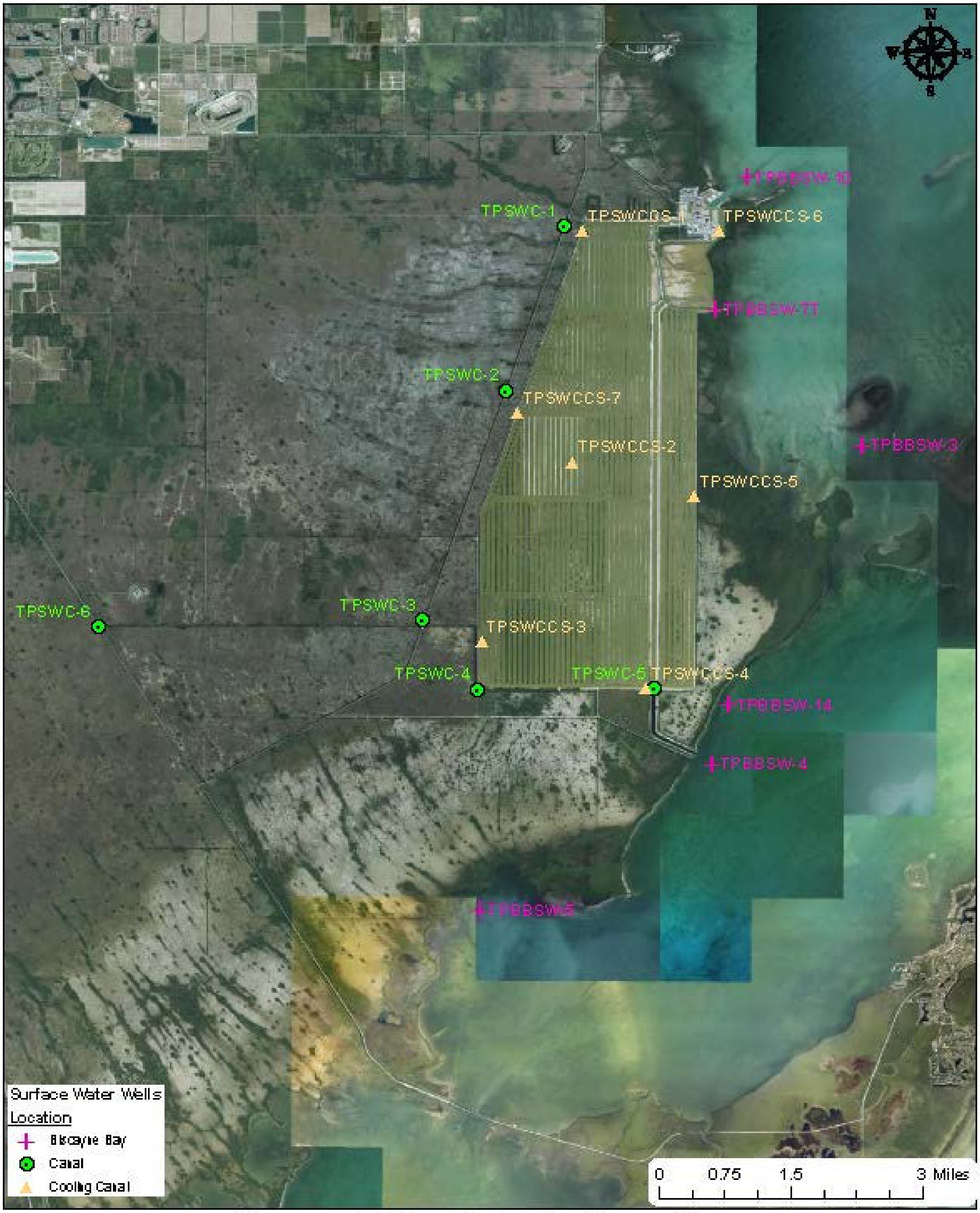

Figure 7. FPL Turkey Point Power Plant
Surface Water Monitoring Locations

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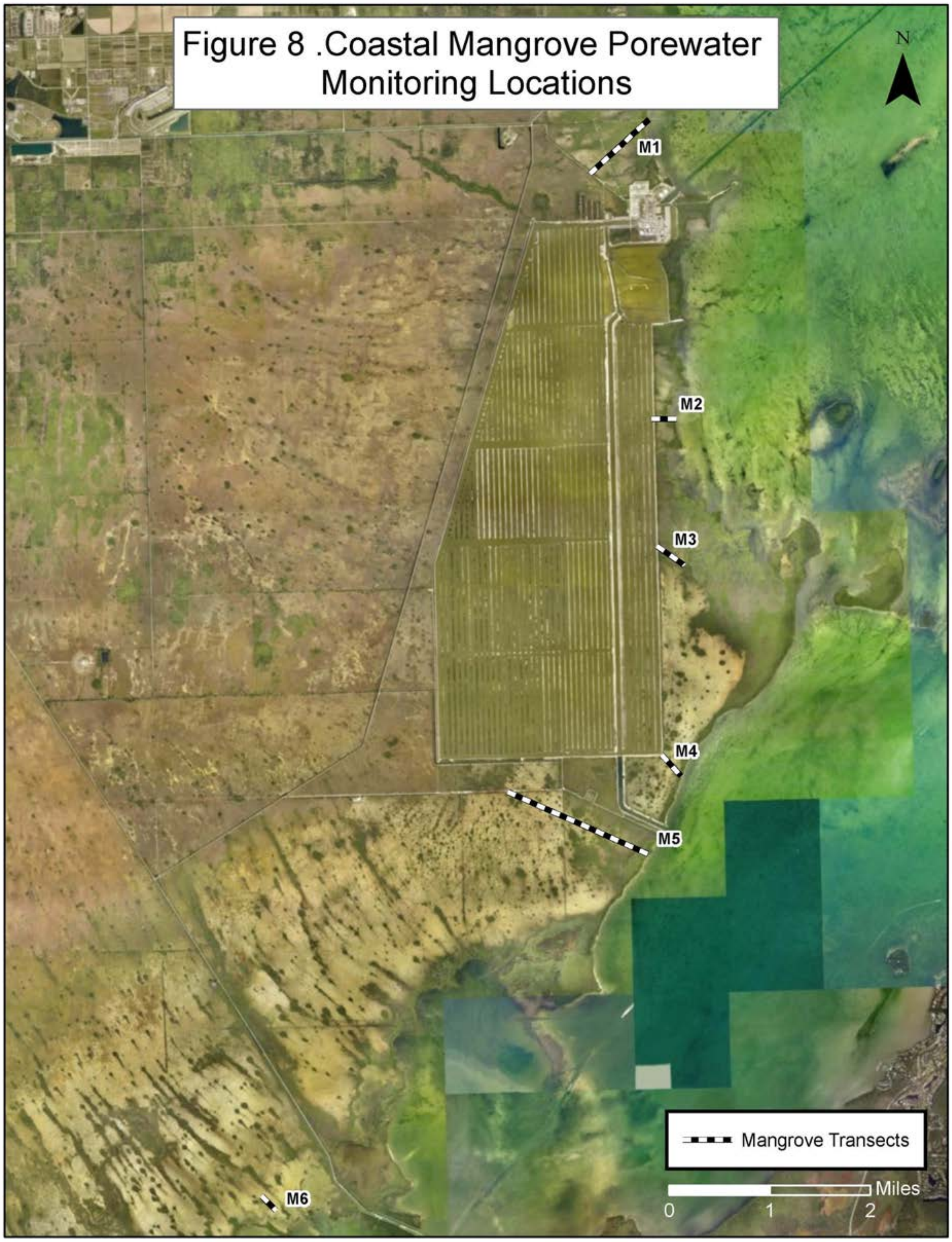


Figure 8 .Coastal Mangrove Porewater Monitoring Locations
N
M1
M2
M3
M4
M5
M6
Mangrove Transects
Miles
0
1
2

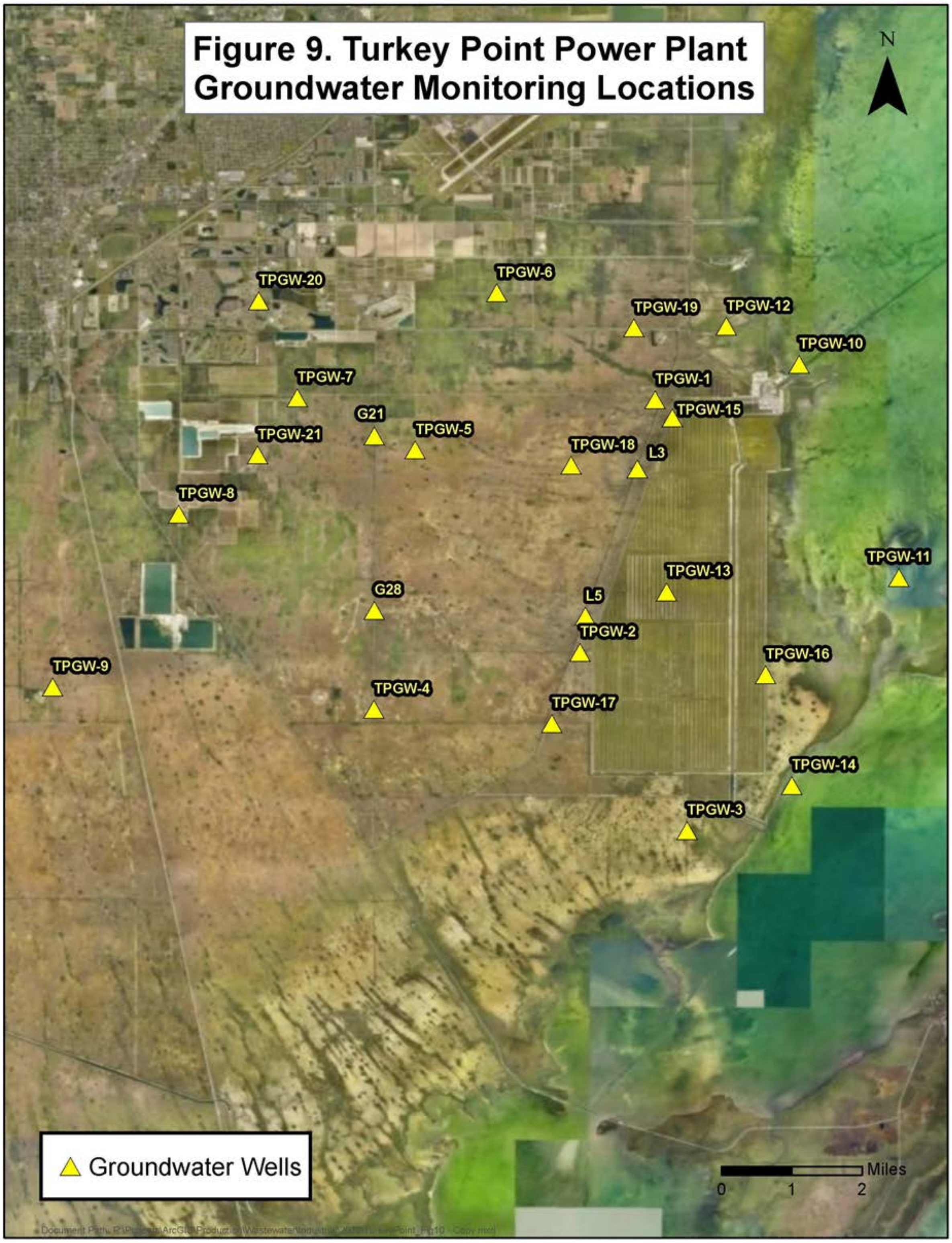
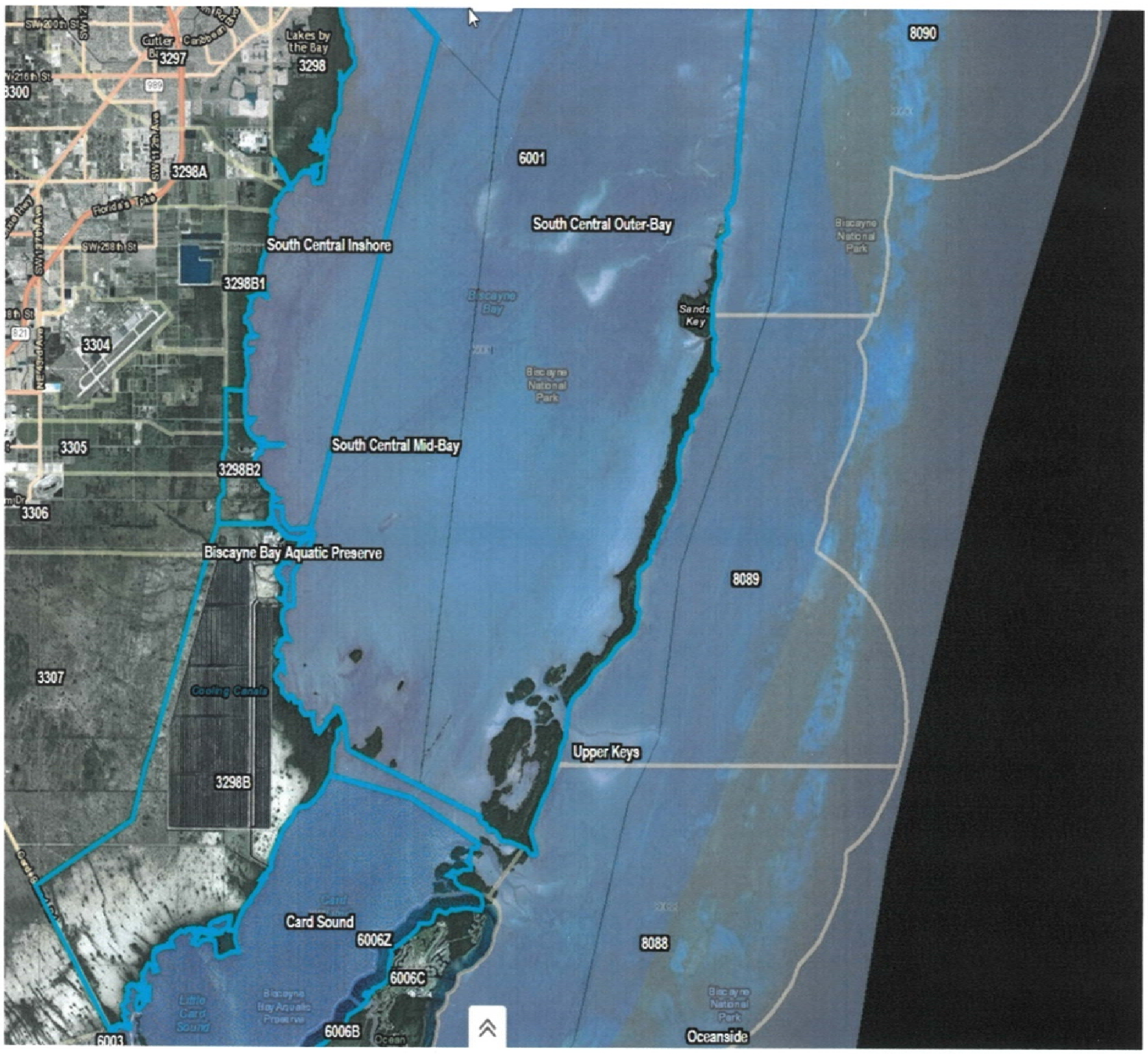


Figure 9. Turkey Point Power Plant
Groundwater Monitoring Locations
N
TPGW-20
TPGW-6
TPGW-19
TPGW-12
TPGW-10
TPGW-7
TPGW-1
TPGW-15
G21
TPGW-5
TPGW-21
TPGW-18
L3
TPGW-8
TPGW-11
TPGW-13
G28
L5
TPGW-2
TPGW-16
TPGW-9
TPGW-4
TPGW-17
TPGW-14
TPGW-3
Groundwater Wells
Miles
0 1 2

Figure 10. South Central and Card Sound Bay Segments



FACT SHEET
FOR
STATE OF FLORIDA INDUSTRIAL WASTEWATER FACILITY PERMIT

PERMIT NUMBER: FL0001562 (Major)

NAME OF PERMITTEE: Florida Power & Light Company (FPL)

FACILITY NAME: Turkey Point Power Plant

FACILITY LOCATION: 9760 SW 344th St, Florida City, Florida 33035
Miami-Dade County

PERMIT WRITERS: Frank Wall, Engineering Specialist IV

Allan Stodghill, P.G., Professional Geologist II

Marc Harris, P.E., Program Administrator

Addendum to Factsheet – The public comment period for the Notice of Draft began on January 15, 2019. During the comment period, the Department received requests to extend the comment period beyond 30 days. A public notice announcing a public meeting was published in the Miami Herald on April 4, 2019. The public meeting was held on May 7, 2019, in Homestead. During the meeting the public had the opportunity to discuss their concerns directly with the Department and FPL representatives. The Department accepted additional comments from the public on the day of the meeting until close of business May 21, 2019. As a result of the comments received and the input from the public meeting, the draft permit was revised as follows:

1. *The facility description section of the permit was updated to more accurately reflect facility operations and surrounding locations along the facility boundaries. Figure 2 was updated with a map showing the boundaries of Biscayne National Park, Biscayne Bay Aquatic Preserve, and Everglades National Park. Figure 3 was replaced with a map showing the boundaries of the Turkey Point facility. Under the wastewater treatment section, the sentence referring to discharges from the facility to surface waters of the State was removed to provide clarity to authorized discharges explicitly expressed in the permit.*

2. *A statement was added to the reuse or disposal groundwater discharge section of the permit regarding Miami-Dade County's regulatory authority under the County's Home Charter Rule. Minor descriptive changes to this section were also provided for clarification.*

3. *Monitoring group D-02A was revised from surface water to porewater in the reuse or disposal section and permit condition II.C.1. The groundwater monitoring group G-001 descriptor "outfall" was replaced with "series".*

4. *Permit condition I.1. The condition was expanded to include reference to Rule 62-520.420, F.A.C., adjacent groundwaters, and compliance schedule items.*

5. *Footnote 2. The footnote was revised by removal of "remedial" and "for achieving compliance with this condition of" as they are not indicative of the requirements of paragraphs 19 and 21 of Consent Order 16-0241.*

6. *Permit condition I.4. The table was expanded to include monitoring for sulfide. Table note "*" well references were revised from TPGW-1 and TPGW-18 to TPGW-L3-18 and TPGW-L5-18. Table note "**" was expanded to clarify sampling frequency and sample collection. Reference to table note "**" was included for the specific conductance. Additionally, the monitoring frequency for temperature was revised from hourly to quarterly consistent with the clarification to note "**".*

7. *New permit condition I.5. The condition was added to the permit which identifies monitoring wells TPGW- 1, 4, 5, 6, 17, 18, and 19 used to assist in the determination of the extent of retraction of the hypersaline plume.*

8. *Permit condition I.7. For clarification, the parameter "N" was revised to Nitrite plus Nitrate, Total (as N). The condition was expanded requiring the facility to implement Department-approved corrective action to address water quality violation and/or impacts within a timetable provided by the Department.*

9. *New permit condition II.A.2. The permit condition prohibits the facility from causing or contributing to a violation of the surface water quality standards or criteria in Rule 62-302, F.A.C.*

10. *Permit condition II.A.4 (Formerly II.A.3). The table was updated to require all parameters to be monitored at SWD-8, SWD-9, SWD-10, SWD-11, and SWD-12, where applicable. Sample type was updated for all instances of Instantaneous to In situ based on comments provided by the facility. Total sodium was revised to total recoverable sodium. For NPDES permitting the two may be used interchangeably.*

11. *Permit condition II.B.1. Sample type was updated for temperature from Instantaneous to In situ based on comments provided by the facility. Total sodium was revised to total recoverable sodium. For NPDES permitting the two may be used interchangeably. Monitoring site OUI-2 was removed from salinity as the value is capture in the calculation provided by CAL-1.*

12. *Permit condition II.B.3. The permit condition was expanded requiring automated hourly data and analytical results from existing individual stations be made available via FPL's EDMS. Reference to Biscayne Bay is not applicable to this permit condition and was therefore removed. The monthly requirement to compile and create an average was revised to quarterly.*

13. *Permit condition II.B.5. The permit condition was revised to require submittal of copies of comments or findings based on report and data submittals reviewed by other agencies to the Department upon request.*

14. *Permit condition II.C.2. Total sodium and total calcium were revised to total recoverable sodium and calcium. For NPDES permitting the two may be used interchangeably. Fluid density units were revised from g/cm3 to g/ml as the two are identical.*

15. *Permit condition II.D.1. Sentence 1 was revised to include reference to a "Department-approved methodology".*

16. *Permit condition II.D.8. This condition was revised to include a new subsection b regarding the formation of nuisances, and reference to Rule 62-302.500(1), F.A.C.*

17. *Permit condition II.D.10. The introductory sentence was revised to include, "Discharge of" and "this requirement is not applicable to", for the purpose of additional clarification.*

18. *Permit condition II.D.15 and footnote 6. The facility was first authorized approval to trial use Optisperse PWR6600 for six months in August of 2018. Additional six-month trials were approved following the initial request. Based on the information provided, Optisperse was added to the approved chemical list of permit condition II.D.15. The facility also indicated that it was no longer trialing anodamine. Based on these changes, footnote 6 is no longer applicable, and hence was removed from the proposed permit.*

19. *Permit condition II.D.19.a. The condition was revised to include reference to Waters of the State.*

20. *Permit condition III.4. The permit condition was expanded requiring vegetation and materials be handled and managed in accordance with the Best Management Practices Plan in Section VII of the permit.*

21. *Schedule item VI.4. The annual nutrient monitoring summary report submittal requirement to begin the third year following permit issuance was removed, and the requirement that it be based on 24 months of data was revised to 12 months of data.*

22. *New schedule items VI.8-10. The new schedule items refer to the hypersaline plume management compliance requirements.*

23. *New permit condition VII.B.3.c.(1)(h). This is a new required component of the waste minimization assessment (WMA) of the Best Management Practices Plan that requires implementation of the Turkey Point CCS Nutrient Management Plan (September 16, 2016), including submittal of annual progress reports.*

24. *Permit condition VIII.E.3. The permit condition was expanded requiring vegetation and materials be handled and managed in accordance with the Best Management Practices Plan in Section VII of the permit.*

25. *Permit condition VIII.F.1. The sentence, "All impoundments other than the CCS shall be inspected at least monthly by qualified personnel.", was removed as the remaining portions of the permit condition provide coverage for the impoundment inspections. The facility indicated that no other impoundments exist at the facility.*

26. *Permit condition VIII.F.5. The permit condition regarding impoundment inspections was expanded requiring maintenance to prevent the growth, accumulation, or spread of any plant species that impact structural integrity of the impoundments. The timeframe was revised to be timely, but no later than 6 months.*

27. *New Section VIII.I. A new standard permit condition VIII.I.1 was added to the permit requiring notification of unauthorized releases or spills be provided to the Department through the Department's Public Notice of Pollution web page.*

28. *The compliance submittal month was revised from November to August 31st throughout the permit.*

Changes as described above to the permit are hereby noted as corresponding changes to the Fact Sheet where applicable.

At the request of the facility, updates and clarifications to the Fact Sheet are identified by italics and underline, while deletions are identified by strikethrough as shown below.

Abbreviations and Acronyms

AADF	Annual Average Daily Flow
AGM	Annual geometric mean
BPJ	Best Professional Judgement
CCS	Cooling Canal System
CO	Consent Order
Deg F	Degrees Fahrenheit
EPA	United States Environmental Protection Agency
Ft	Feet
F.A.C.	Florida Administrative Code
FPL	Florida Power & Light Company
F.S.	Florida Statutes
g/cm^3	Grams per cubic centimeter
ICW	Intake Cooling Water
MW	Megawatts
ug/L	Microgram per liter
umhos/cm	Micromhos per centimeter
mg/L	Milligrams per liter
MGD	Million Gallons per Day
NPDES	National Pollutant Discharge Elimination System
NTU	Nephelometric Turbidity Unit
NAICS	North American Industry Classification System
NAVD	North American Vertical Datum
NOV	Notice of Violation
OGC	Office of General Counsel
OTCW	Once-through Cooling Water
OFW	Outstanding Florida Water
pCi/L	Picocuries per liter
PCU	Platinum-Cobalt Unit
PSU	Practical Salinity Unit
P.E.	Professional Engineer
P.G.	Professional Geologist
SFWMD	South Florida Water Management District
SIC	Standard Industrial Classification
s.u.	Standard Units
TDS	Total Dissolved Solids
TMDL	Total Maximum Daily Load
USGS	United States Geological Survey

BACKGROUND

1. CHRONOLOGY OF APPLICATION

File Number:	FL0001562-012-IW1N
Application Submittal Date:	October 22, 2009
Additional Information:	March 12th, June 1st, August 16th, September 16th & December 13th, 2010; September 30th, 2016; February 10th & 22nd, April 24th, May 5th, August 16th & 29th & October 16th, 2017; August 3rd, September 11th & 14th, October 29th, November 5th, December 4th, 2018, and other dates.
Notice of Draft:	January 2, 2019 (issued); January 15, 2019 (published)
Public Meeting:	April 4, 2019 (published); May 7, 2019 (public meeting); May 21, 2019 (comment period closed)

2. FACILITY DESCRIPTION

Standard Industrial Classification (SIC) Code: 4911 - Electrical Generation.

316(b): The facility does not have any cooling water intake structures, and therefore, is not subject to Section 316(b) of the Clean Water Act.

North American Industry Classification System (NAICS): 221112 - Fossil Fuel Electric Power Generation, 221113 – Nuclear Electric Power Generation.

Existing Cooling Canal System Permitted Capacity: 2763 Million Gallons per Day (MGD) Annual Average Daily Flow (AADF)

Proposed Increase in Permitted Capacity: No increase

Proposed Total Permitted Capacity: 2763 MGD AADF

The Turkey Point facility, which began operation in 1967, is located on approximately 11,000 acres in unincorporated southeast Miami-Dade County about 25 miles south of Miami and about nine miles east of Florida City and Homestead (See Figure 1, FPL Turkey Point Location Map). Biscayne National Park, established in 1980, lies adjacent to eastern portions of the facility. The Biscayne Bay Aquatic Preserve, established in 1974, is southeast of the facility. Everglades National Park, established in 1934, is to the south and west (see Figure 2, Turkey Point Power Plant, National Parks, and Aquatic Preserve).

West of the facility are the South Florida Water Management District (SFWMD) L-31E Canal, the historic C-106 Canal (Model Lands North Canal), and the historic C-107 Canal (Model Lands South Canal). Southeast of the facility is the Card Sound *Discharge* Canal and southwest and south is the SFWMD S-20 Discharge Canal. The remnant canals at Turtle Point and the Barge Basin are located east northeast and northeast of the facility, respectively (see Figure 3, Turkey Point Power Plant Internal Outfall and Dam Structures and Adjacent Canals).

The facility consists of three electrical generating units: two nuclear units (Units 3 and 4) and one natural gas-fired combined cycle unit (Unit 5). Units 3, 4, and 5 began commercial operation in 1972, 1973, and 2007, respectively. Units 3 and 4 each have a nominal capacity of 815 Megawatts (MW) and Unit 5 has a nominal capacity of 1209 MW. Units 3, 4 and 5 are also regulated under the Florida Electrical Power Plant Siting Act (License No. PA03-045).

FPL owns and operates a recirculating cooling canal system (CCS) at the facility *that began permitted operation in 1973*. The CCS provides a heat removal function for the cooling water from Units 3 and 4. Unit 5 dissipates heat through cooling tower cells. The heated water generated by operation of Units 3 and 4 is released to the recirculating CCS and returned to Units 3 and 4. The temperature of the water entering Units 3 and 4 is regulated by the U.S. Nuclear Regulatory Commission under the Atomic Energy Act. Groundwater withdrawals from the Floridan aquifer is the source of cooling water for Unit 5, and is authorized under License No. PA03-045. Groundwater from the Floridan aquifer is also used as makeup water to help offset evaporation within the CCS.

The facility, as originally designed and constructed, included a once-through cooling water (OTCW) system (i.e., point source discharge of heated wastewater to surface waters). The facility obtained cooling water by drawing surface water from an intake channel connected to Biscayne Bay, and discharged the heated wastewater into Biscayne Bay and Card Sound through a series of discharge canals. FPL was required to construct the CCS to satisfy a 1971 consent judgment with the U.S. Department of Justice. The judgement required the permitting, construction, operation, and maintenance of the CCS as a recirculating cooling water system (i.e., no point source discharges of heated wastewater to surface waters). In addition, the judgement allowed FPL to directly discharge CCS water through the Card Sound *Discharge* Canal to Card Sound, provided the discharge met the stipulated requirements in the judgement. This allowance was to prevent the excessive concentration of salt in the CCS water.

In 1972, the U.S. Atomic Energy Commission prepared an environmental impact statement (EIS) with respect to the construction of the cooling canal system. The EIS indicated that water from the CCS would discharge to groundwater and that some of that groundwater could seep into adjacent surface waters (Biscayne Bay and Card Sound). The EIS acknowledged the potential for minimal adverse impacts on flora (red mangroves) and fauna (shallow benthic communities). The approach to groundwater seepage set forth ~~in the draft permit is~~ *in the EIS was* to monitor the effects of groundwater seepage and address any adverse environmental impacts that may develop.

The construction of the CCS *began in 1972* ~~was completed in August 1973~~. *Construction was completed and operations permitted in 1973*. ~~The CCS became fully operational in 1978 and~~ *The CCS* occupies an area approximately 2 miles wide by 5 miles long. This area includes a network of 168 miles of earthen canals covering approximately 6,900 acres of which 4,370 acres are water surface. The circulation route from the plant discharge to plant intake is 13.2 miles and takes approximately 44 hours to complete. The CCS canals are excavated into the native rock and the underlying surficial aquifer, which is *part of* the Biscayne aquifer.

The CCS perimeter berms were constructed using structural road base material and excavated rock fill. Berm widths around the perimeter of the CCS range from about 25 feet to over 100 feet, with an average width of about 50 feet. Interior berms separating the canal sections are primarily covered with deposited excavated soils from the CCS canals.

The perimeter includes three small, manmade dams: two earthen dams each with an internal cement bentonite slurry wall (Hotel 2 north of Card Sound *Discharge* Canal and one located at Turtle Point); and a cellular cofferdam located near the plant in the Barge Basin.

In September 2016, the CCS periphery including dams, dikes, berms, and appurtenant structures were inspected by an independent qualified safety professional in accordance with the Department's Consent Order (CO) (OGC No. 16-0241) that was issued in June 2016. For more information on the CO, see Part II Section 3 of this Fact Sheet. The cofferdam was inspected both above and below the waterline. No structural defects or breaches were identified in the resulting report, dated September 2016, submitted by FPL to the Department. The report did, however, include recommendations for maintaining and protecting the long-term integrity of the CCS. In early 2018, FPL completed a number of the recommendations, including: (1) repair of the tie rods, walers, steel corrosion, and crest road on the barge canal cofferdam; (2) backfill of the old C-107 canal (now S-20 Discharge Canal) cut on the CCS side of bank; (3) stabilization of slopes (both sides) for the Hotel 2 dam; and (4) removal of trees greater than 4 inches in diameter from perimeter berm slopes.

In addition, the report included recommendations to inspect: (1) the CCS once every five years for the entire perimeter; and (2) the four small dams annually. Section VIII of the draft permit requires inspection of the CCS periphery, including the three dams, above and below the surface waterline for the entire perimeter by an independent qualified, State-registered professional engineer on a five-year basis and annually by a qualified, State-registered professional engineer. The term qualified means having successfully completed the Mine Safety and Health Administration Qualification for Impoundment Inspection course in addition to the Annual Retraining for Impoundment Qualification, or equivalent qualifications.

Furthermore, the draft permit requires FPL to submit to the Department an annual report of all impoundment inspections and maintenance activities, including corrective actions made in response to inspections, summarizing findings of all monitoring activities including the annual thermal efficiency evaluation of the CCS, remediation measures pertaining to the structural integrity, design, construction, and operation and maintenance of the CCS, and all other activities undertaken to repair or maintain the CCS.

The Department's CO requires the CCS to achieve a minimum 70 percent thermal efficiency and to control temperature and salinity. FPL has submitted a thermal efficiency plan to address water stage management, vegetation control, dredging, chemical additives to the CCS for facility operation, and upset recovery. FPL is implementing the efficiency plan and has been able to achieve greater than 70 percent thermal efficiency, and following permit issuance is required, under Section VIII of this draft permit, to monitor the thermal efficiency of the CCS in the months of April and August of each year.

Based on monitoring results, ~~FPL~~ *locations were* identified in the Turtle Point Canal and Barge Basin ~~locations~~ where water originating from the CCS ~~may~~ *could have* reach*ed* tidal surface waters connected to Biscayne Bay. The CO requires FPL to conduct restoration projects in the above canal and basin area to prevent releases of groundwater from the CCS to surface waters connected to Biscayne Bay that result in exceedances of surface water quality standards in Biscayne Bay. ~~The restoration projects are on schedule to be completed in accordance with the schedule prescribed in the CO.~~ *The Turtle Point Canal restoration project is complete, and the Barge Basin restoration project is on schedule to be completed in accordance with the schedule prescribed in the CO.*

The CCS is unlined, and therefore, discharges to the Biscayne aquifer beneath the CCS. The Biscayne aquifer has an approximate depth of 100 feet below land surface on the westside of the CCS and an approximate depth of 130 feet on the east side out in the Bay. Groundwater beneath the CCS is Class G-III, non-potable water with a total dissolved solids (TDS) content of 10,000 milligrams per liter (mg/L) or greater.

Class G-III groundwater is also present west (inland) of the CCS, at depth within the Biscayne aquifer. Present above this inland Class G-III groundwater is Class G-II groundwater, potable water that has a TDS content of less than 10,000 mg/L. Class G-II groundwater lies to the west, northwest, north of the CCS. For purposes of this permit the contact or intersection of Class G-II and Class G-III groundwater is called a "saltwater interface".

Saline water from the CCS has moved, at depth, westward of the L-31E Canal in excess of those amounts that would have occurred without the existence of the CCS. Elevated salinity levels in the CCS cause, or at a minimum contribute to, the hypersaline discharges into the groundwater. The CO requires FPL to cease discharges from the CCS that impair the reasonable and beneficial use of the adjacent Class G-II groundwaters to the west of the CCS. FPL is currently conducting remedial activities to address hypersaline waters that have extended beyond the facility's western boundaries for which the compliance point is identified as the L-31E Canal per the CO.

3. RETIREMENT OF UNITS 1 AND 2

Former Units 1 and 2 began operation in 1967 and 1968, respectively. These units were converted from generation mode to synchronous condenser mode to provide voltage support to the transmission system in 2017 and 2011, respectively. The converted units do not generate wastewater. However, stormwater run-off from the units is covered under this permit.

Process wastewater and stormwater associated with Units 1 and 2 were released to the CCS through an internal outfall designated as outfall I-002. Outfall I-002 piping from the basins to the CCS *has been removed*. ~~is scheduled for removal by January 1, 2019. Piping to the basins has already been capped.~~ Therefore, internal outfall I-002 has been removed from the draft permit.

4. DESCRIPTION OF WASTEWATER

Stormwater and wastewater associated with power generation and ancillary activities are released to the CCS. Point source discharges, as defined in Rule 62-620.200(37), F.A.C., from the facility to surface waters of the State are not authorized under this draft permit.

Stormwater runoff associated with loading and unloading operations, outdoor storage, outdoor process activities, and ancillary maintenance activities is directed toward the CCS. The quantities of stormwater generated from these activities are dependent on many variables, including the length and intensity of the storm event. Stormwater may come into contact with petroleum, oil, and lubricants used in industrial equipment which may leak onto impervious areas and become entrained in stormwater runoff. Stormwater may also come into contact with petroleum products, heavy metals, salts, anti-freeze and other automotive fluids which may be present at the onsite closed-loop vehicle wash area and vehicle access areas. Maintenance that consists of earth disturbance activities may also be a significant source of sediment. This draft permit requires development and implementation of a Best Management Practices Plan (see Section II.2.c.).

Wastewater generated by Units 3 and 4 (see flow diagram in Figure 4) includes intermittent chemical volume control system including wet lay-up, feedwater condensate including wet lay-up, on-line chemical analyzer, steam generator blowdown, condensate polisher backwash, reverse osmosis reject, circulating water pumps seal water, alternate flow from the circulating water pump seal water tank, non-equipment area stormwater, maintenance/wash through equipment area/closed cooling water system maintenance, plant intake screen wash, and non-contact once-through cooling water (OTCW), which is denoted as condenser and intake cooling water (ICW) on the figure.

Wastewater generated by Unit 5 (see flow diagram Figure 5) includes cooling water, emergency generator backup cooling water, non-equipment area stormwater, equipment area stormwater and plant drains following oil/water separation, and wastewater sump discharge which includes heat recovery steam generator blowdown, wastewater treatment system blowdown, and cooling water treatment reject.

I. PURPOSE

This is a renewal of the existing individual industrial wastewater discharge permit No. FL0001562 for the Turkey Point Power Plant. *This permit has been renewed in various forms since the early 1970s when the CCS became operational.* The objective of this permit is to ensure the cooling canal system (CCS) water does not impair designated uses of adjacent surface waters and groundwater as defined in Chapters 62-302, and 62-520, F.A.C. Elements of the draft permit are as follows.

1. DISCHARGES AND MONITORING

a. Internal Outfall and CCS

Wastewater enters the CCS at Internal Outfall I-001 (see Figure 3), which is the only permitted outfall authorized by this permit. This permit retains previous monitoring requirements for Internal Outfall I-001. This permit also includes additional monitoring at Internal Outfall I-001 and locations within the CCS, as well as locations beyond the CCS, necessary to characterize wastewater for evaluation of CCS wastewater beyond the facility boundaries. The 1972 Environmental Impact Statement acknowledges that some seepage of water from the CCS may reach surface waters. To the extent that such seepage occurs, it shall not cause or contribute to a violation of the surface water quality standards in Chapter 62-302, F.A.C. (see Tables II.1 and II.2 and Figure 6, Turkey Point Power Plant Groundwater, Surface Water, and Porewater Monitoring Locations, Figure 7, Turkey Point Power Plant Surface Water Monitoring

Locations, Figure 8, Coastal Mangrove Porewater Monitoring Locations, and Figure 9, Turkey Point Power Plant Groundwater Monitoring Locations).

Table II.1 Monitoring Locations Within the Cooling Canal System

OUI - Sampling location for internal outfall designated as I-001.
TPSWCCS - Turkey Point Surface Water Cooling Canal System.

Sample Station ID	Location	Latitude			Longitude		
		o	'	"	o	'	"
OUI-1	Cooling water discharge prior to entering the feeder canal to the CCS	25	26	00.60	80	20	15.64
TPSWCCS-1	Northwest corner of the CCS	25	25	56.0	80	21	00.8
TPSWCCS-2	Central portion of the CCS	25	23	39.0	80	21	06.7
TPSWCCS-3	Southwestern portion of the CCS	25	21	52.4	80	22	02.4
TPSWCCS-4	Southern portion of the CCS near the Hotel 2 Dam	25	21	25.3	80	20	23.1
TPSWCCS-5	East-central portion of the CCS	25	23	18.4	80	19	54.4
TPSWCCS-6	Northeastern portion of the CCS	25	25	56.2	80	19	40.2
TPSWCCS-7	West-central portion of the CCS	25	24	07.6	80	21	39.4

Table II.2 Parameters monitored in the Cooling Canal System

Parameter	**Units**	**Rationale**
Temperature, Water	Deg F	62-4.070, and 62-620.320, F.A.C. (BPJ)
Solids, Total Suspended	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Biochemical Oxygen Demand (BOD)	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Dissolved Oxygen (DO), % Saturation	percent	62-4.070, and 62-620.320, F.A.C. (BPJ)
Oxygen Reduction Potential	mv	62-4.070, and 62-620.320, F.A.C. (BPJ)
pH	s.u.	62-4.070, and 62-620.320, F.A.C. (BPJ)
Color	PCU	62-4.070, and 62-620.320, F.A.C. (BPJ)
Solids, Total Dissolved	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Salinity	PSU	62-4.070, and 62-620.320, F.A.C. (BPJ)
Specific Conductance	umhos/cm	62-4.070, and 62-620.320, F.A.C. (BPJ)
Turbidity	NTU	62-4.070, and 62-620.320, F.A.C. (BPJ)
Nitrogen, Ammonia, Total (as N)	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Ammonia, Total Unionized (as NH_3)	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Ammonium ion (NH_4^+)	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Nitrite plus Nitrate, Total (as N)	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Nitrogen, Kjeldahl, Total (as N)	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Nitrogen, Total	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Phosphate, Ortho (as PO_4)	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Phosphorous, Total	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Chlorophyll *a*	ug/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Copper, Total Recoverable	ug/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Iron, Total Recoverable	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Zinc, Total Recoverable	ug/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Boron, Total Recoverable	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Chlorides (as Cl)	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Magnesium, Total Recoverable	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)

Parameter	Units	Rationale
Sodium, Total	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Sulfate, Total	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Sulfide, Total	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Tritium	pCi/L	62-4.070, and 62-620.320, F.A.C. (BPJ)

b. Groundwater Monitoring (Groundwater Monitoring Group G-001)

Under this permit, CCS discharges to groundwater, both at and beyond the facility, will be monitored using a network of sixty-five monitoring wells (see Figure 9). The Biscayne aquifer will be monitored both laterally and vertically, with monitoring wells set in shallow, intermediate and deep zones. As shown in Figure 9, the network includes groundwater monitoring wells located in Biscayne Bay, the CCS, near the facility perimeter, and westward, or inland, of the facility.

During the period of operation authorized by this permit, FPL shall sample groundwater from the Biscayne aquifer from the following monitoring wells:

Table II.3 Groundwater Monitoring Well Locations

TPGW - Turkey Point Groundwater.
S - shallow, M - intermediate, and D - deep monitoring zones.
G-wells: Monitoring wells installed in 1972.
L-wells: Monitoring wells installed in 1974.

Monitoring Well ID	Description of Monitoring Location	Latitude			Longitude		
		o	'	"	o	'	"
TPGW-1S	West of Canal L-31E, west of northwest corner of the CCS (shallow)	25	26	4.7	80	21	15.8
TPGW-1M	West of Canal L-31E, west of northwest corner of the CCS (intermediate)	25	26	4.7	80	21	15.8
TPGW-1D	West of Canal L-31E, west of northwest corner of the CCS (deep)	25	26	4.7	80	21	15.8
TPGW-2S	West of the south-central portion of the CCS (shallow)	25	22	54.2	80	22	11.4
TPGW2M	West of the south-central portion of the CCS (intermediate)	25	22	54.2	80	22	11.4
TPGW-2D	West of the south-central portion of the CCS (deep)	25	22	54.2	80	22	11.4
TPGW-3S	South of the CCS (shallow)	25	20	42.1	80	20	51.9
TPGW-3M	South of the CCS (intermediate)	25	20	42.1	80	20	51.9
TPGW-3D	South of the CCS (deep)	25	20	42.1	80	20	51.9
TPGW-4S	Southwest Model Lands, at Tallahassee Road (shallow)	25	22	12.0	80	24	44.1
TPGW-4M	Southwest Model Lands, at Tallahassee Road (intermediate)	25	22	12.0	80	24	44.1
TPGW-4D	Southwest Model Lands, at Tallahassee Road (deep)	25	22	12.0	80	24	44.1
TPGW-5S	Northwest Model Lands – east of Tallahassee Road (shallow)	25	25	23.9	80	24	13.3
TPGW-5M	Northwest Model Lands – east of Tallahassee Road (intermediate)	25	25	23.9	80	24	13.3
TPGW-5D	Northwest Model Lands – east of Tallahassee Road (deep)	25	25	23.9	80	24	13.3
TPGW-6S	Northwest of the CCS, east of Homestead – Miami Speedway (shallow)	25	27	20.3	80	23	13.0
TPGW-6M	Northwest of the CCS, east of Homestead – Miami Speedway (intermediate)	25	27	20.3	80	23	13.0
TPGW-6D	Northwest of the CCS, east of Homestead – Miami Speedway (deep)	25	27	20.3	80	23	13.0
TPGW-7S	Northwest Model Lands (shallow)	25	26	02.5	80	25	40.7
TPGW-7M	Northwest Model Lands (intermediate)	25	26	02.5	80	25	40.7
TPGW-7D	Northwest Model Lands (deep)	25	26	02.5	80	25	40.7
TPGW-8S	West central Model Lands (shallow)	25	24	36.4	80	27	08.7
TPGW-8M	West central Model Lands (intermediate)	25	24	36.4	80	27	08.7
TPGW-8D	West central Model Lands (deep)	25	24	36.4	80	27	08.7

Monitoring Well ID	Description of Monitoring Location	Latitude			Longitude		
		o	'	"	o	'	"
TPGW-9S	West of Card Sound Canal Road, southwest of CCS (shallow)	25	22	28.6	80	28	41.9
TPGW-9M	West of Card Sound Canal Road, southwest of CCS (intermediate)	25	22	28.6	80	28	41.9
TPGW-9D	West of Card Sound Canal Road, southwest of CCS (deep)	25	22	28.6	80	28	41.9
TPGW-10S	Biscayne Bay, channel entrance to Barge Basin (shallow)	25	26	27.4	80	19	29.0
TPGW-10M	Biscayne Bay, channel entrance to Barge Basin (intermediate)	25	26	27.4	80	19	29.0
TPGW-10D	Biscayne Bay, channel entrance to Barge Basin (deep)	25	26	27.4	80	19	29.0
TPGW-11S	Biscayne Bay, east of the CCS (shallow)	25	23	49.4	80	18	15.0
TPGW-11M	Biscayne Bay, east of the CCS (intermediate)	25	23	49.4	80	18	15.0
TPGW-11D	Biscayne Bay, east of the CCS (deep)	25	23	49.4	80	18	15.0
TPGW-12S	North of the CCS (shallow)	25	26	55.4	80	20	22.9
TPGW-12M	North of the CCS (intermediate)	25	26	55.4	80	20	22.9
TPGW-12D	North of the CCS (deep)	25	26	55.4	80	20	22.9
TPGW-13S	In the central portion of the CCS (shallow)	25	23	39.0	80	21	07.1
TPGW-13M	In the central portion of the CCS (intermediate)	25	23	39.0	80	21	07.1
TPGW-13D	In the central portion of the CCS (deep)	25	23	39.0	80	21	07.1
TPGW-14S	Biscayne Bay, southeast of the CCS (shallow)	25	21	15.5	80	19	34.5
TPGW-14M	Biscayne Bay, southeast of the CCS (intermediate)	25	21	15.5	80	19	34.5
TPGW-14D	Biscayne Bay, southeast of the CCS (deep)	25	21	15.5	80	19	34.5
TPGW-15S	Northwest corner of CCS (shallow)	25	25	56.9	80	21	2.5
TPGW-15M	Northwest corner of CCS (intermediate)	25	25	56.9	80	21	2.5
TPGW-15D	Northwest corner of CCS (deep)	25	25	56.9	80	21	2.5
TPGW-16S	East of the south-central portion of the CCS (shallow)	25	22	37.7	80	19	53.8
TPGW-16M	East of the south-central portion of the CCS (intermediate)	25	22	37.7	80	19	53.8
TPGW-16D	East of the south-central portion of the CCS (deep)	25	22	37.7	80	19	53.8
TPGW-17S	East of the L-31E canal, adjacent to S-20 structure (shallow)	25	22	71.4	80	22	53.2
TPGW-17M	East of the L-31E canal, adjacent to S-20 structure (intermediate)	25	22	1.4	80	22	32.2
TPGW-17D	East of the L-31E canal, adjacent to S-20 structure (deep)	25	22	1.4	80	22	32.2
TPGW-18S	Model Lands, west of L-3 (shallow)	25	25	12.5	80	22	17.8
TPGW-18M	Model Lands, west of L-3 (intermediate)	25	25	12.5	80	22	17.8
TPGW-18D	Model Lands, west of L-3 (deep)	25	25	12.5	80	22	17.8
TPGW-19S	Model Lands, north of Florida City Canal (shallow)	25	26	54.2	80	21	31.3
TPGW-19M	Model Lands, north of Florida City Canal (intermediate)	25	26	54.2	80	21	31.3
TPGW-19D	Model Lands, north of Florida City Canal (deep)	25	26	54.2	80	21	31.3
TPGW-20D	Adjacent to City of Homestead baseball complex	25	27	19.9	80	26	10.5
TPGW-21S	Converted USGS well G-3164 (shallow)	25	25	20.2	80	26	10
TPGW-21M	Converted USGS well G-3164 (intermediate)	25	25	20.2	80	26	10
TPGW-21D	Converted USGS well G-3164 (deep)	25	25	20.2	80	19	10
L-3	East of the L-31E canal, north-central portion of the CCS (Not Automated). This well is an open-hole well, monitored at approximately 18 feet and 58 feet below land surface.	25	25	09.7	80	21	28.7
L-5	East of the L-31E canal, south-central portion of the CCS (Not Automated). This well is an open-hole well, monitored at approximately 18 feet and 58 feet below land surface.	25	23	20.9	80	22	7.3
G-28	Tallahassee Rd, south of Model Lands basin (Not Automated). This well is an open-hole well, monitored at approximately 18 feet and 58 feet below land surface.	25	23	25.5	80	24	43.6
G-21	Tallahassee Rd, north of Model Lands basin (Not Automated). This well is an open-hole well, monitored at approximately 18 feet and 58 feet below land surface.	25	25	34.8	80	24	42.9

Under the FPL Turkey Point Power Plant Groundwater, Surface Water, and Ecological Monitoring Plan, which began in 2009, FPL conducted an assessment regarding the identification of potential tracer monitoring parameters for use in determining the occurrence of CCS waters in the region. FPL documented their findings in the August 2011 annual monitoring report submitted to SFWMD and the Department. Based on these findings, the Department identified tritium in conjunction with major seawater ions and other constituents to be monitored as a means of fingerprinting to be used by FPL in identifying CCS waters in the region. The wells in Table II.3 above shall be monitored for the following parameters.

Table II.4 Parameters monitored in Groundwater

Parameter	Units	Rationale
Temperature	Deg F	62-520, F.A.C.
Water Level Relative to NAVD	ft	62-520, F.A.C.
Specific Conductance	umhos/cm	62-520, F.A.C.
Salinity	PSU	62-520, F.A.C.
Fluid Density	g/cm^3	62-520, F.A.C.
pH	s.u.	62-520, F.A.C.
Solids, Total Dissolved (TDS)	mg/L	62-520, F.A.C.
Chloride (as Cl)	mg/L	62-520, F.A.C.
Sodium, Total	mg/L	62-520, F.A.C.
Calcium, Total	mg/L	62-520, F.A.C.
Potassium, Total	mg/L	62-520, F.A.C.
Iron, Total Recoverable	mg/L	62-520, F.A.C.
Tritium	pCi/L	Tracer (BPJ)
Nitrogen, Ammonia, Total (as N)	mg/L	62-520, F.A.C.
Ammonium ion (NH_4^+)	mg/L	62-520, F.A.C.
Ammonia, Total Unionized (as NH_3)	mg/L	62-520, F.A.C.
Nitrite plus Nitrate, Total (as N)	mg/L	62-520, F.A.C.
Nitrogen, Kjeldahl, Total (as N)	mg/L	62-520, F.A.C.
Nitrogen, Total	mg/L	62-520, F.A.C.
Phosphorus, Total (as P)	mg/L	62-520, F.A.C.
Phosphate, Ortho (as PO_4)	mg/L	62-520, F.A.C.
Boron, Total Recoverable	mg/L	62-520, F.A.C.
Magnesium, Total Recoverable	mg/L	62-520, F.A.C.
Sulfate, Total	mg/L	62-520, F.A.C.

The above listed parameters are report only except for Nitrite plus Nitrate, Total (as N), which has a limit of 10 mg/L in samples collected from monitoring wells TPGW-1, and TPGW-18.

Tritium will be collected quarterly and is being monitored as a tracer for identifying contributions of CCS water to the Biscayne aquifer.

In addition, permit condition II.D.8 prohibits the discharge of nuisance, acutely toxic, carcinogenic, mutagenic, teratogenic, and dangerous components in accordance with Rules 62-520.400, and 62-520.430, F.A.C.

c. Surface Water Monitoring (Biscayne Bay, L-31E Canal, S-20 Discharge Canal, Card Sound *Discharge* Canal) (Surface Water Monitoring Group D-01A)

Surface water monitoring as shown in Table II.5 is required in this permit to confirm that discharge from the CCS to groundwater does not impair the designated use of contiguous surface waters pursuant to Rule 62-520.310(2), F.A.C. Therefore, the same parameters are monitored in the CCS and surface waters of the State as discussed below.

Biscayne Bay is subject to the estuary-specific numeric nutrient criteria in Paragraph 62-302.532(1)(h), F.A.C. The Department updated the 303d lists of impaired waters in June 2017, identifying the majority of Biscayne Bay, including the South Central Biscayne Bay segments east of the facility as impaired for nutrients based on chlorophyll *a* levels. Section 403.067, F.S., implements section 303(d) of the Clean Water Act, and requires the Department to develop lists of impaired waters, and to develop Total Maximum Daily Loads (TMDL) for those waters. The Card

Sound segment of Biscayne Bay to the south of the facility is not identified as impaired for nutrients. ~~Biscayne Bay is not identified as impaired for any other parameters and has not been previously identified as impaired for nutrients.~~ Figure 10 provides a map of Biscayne Bay showing South Central and Card Sound bay segments.

In accordance with Paragraphs 62-302.700(9)(h)5, F.A.C., (Biscayne Bay, Cape Florida) and 62-302.700(9)(h)6, F.A.C., (Biscayne Bay, Card Sound) Biscayne Bay is an Outstanding Florida Water (OFW), and parts of the South Central and Card Sound bay segments are within the Biscayne Bay Aquatic Preserve. "Outstanding Florida Waters" means waters designated by the Environmental Regulation Commission as worthy of special protection because of their natural attributes as defined by Rule 62-302.200(26), F.A.C. Additionally, in accordance with Paragraph 62-302.700(9)(a)1, F.A.C., Biscayne National Park is an OFW and encompasses much of the Biscayne Bay estuary. Biscayne National Park is also an Outstanding National Resource Water in accordance with Paragraph 62-302.700(10)(a)1, F.A.C. "Outstanding National Resources Waters" means waters designated by the Environmental Regulation Commission that are of such exceptional recreational or ecological significance that water quality should be maintained and protected as defined by Rule 62-302.200(27), F.A.C.

The L-31E canal is approximately parallel to the western boundary of the CCS, and the S-20 Discharge Canal is parallel to the southwest and south sides of the CCS. These canals are controlled by the SFWMD. Salinity in the canals fluctuates seasonally.

The L-31E canal was primarily constructed as a barrier to prevent salinity intrusion to locations west of the canal. The L-31E canal collects water from other drainage canals in the area. The L-31E canal discharges into Biscayne Bay through the S-20 Discharge Canal.

Table II.5 Surface Water Monitoring Locations

TPBBSW - Turkey Point Biscayne Bay Surface Water.
TPSWC - Adjacent Surface Water Canals.
T - Top samples, B - Bottom samples.

Sample Station ID	Location	Latitude			Longitude		
		o	'	"	o	'	"
TPBBSW-3	Biscayne Bay	25	23	49.38	80	18	14.82
TPBBSW-4	Biscayne Bay	25	20	40.34	80	19	43.90
TPBBSW-5	Biscayne Bay	25	19	13.69	80	22	1.70
TPBBSW-7T	Biscayne Bay near Turtle Point Canal Dam	25	25	9.99	80	19	42.15
~~TPBBSW-8~~	~~Terminus of Barge Canal~~	~~25~~	~~25~~	~~12.61~~	~~80~~	~~19~~	~~29.89~~
TPBBSW-10	Biscayne Bay	25	26	27.83	80	19	22.92
TPBBSW-14	Biscayne Bay	25	25	15.50	80	19	34.50
TPSWC-1B TPSWC-1T	L-31E Canal	25	25	58.44	80	21	11.87
TPSWC-2B TPSWC-2T	L-31E Canal	25	24	21.20	80	21	46.30
TPSWC-3B TPSWC-3T	L-31E Canal	25	22	10.47	80	22	33.00
TPSWC-4B TPSWC-4T	S-20 Canal	25	21	24.10	80	22	3.00
TPSWC-5B TPSWC-5T	Card Sound *Discharge* Canal at Hotel 2 Dam	25	21	24.62	80	20	18.70

Table II.6 Parameters monitored in Surface Waters

Parameter	Units	Rationale
Temperature, Water	Deg F	62-4.070, and 62-620.320, F.A.C. (BPJ)
pH	s.u.	62-4.070, and 62-620.320, F.A.C. (BPJ)
Solids, Total Dissolved (TDS)	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Salinity	PSU	62-4.070, and 62-620.320, F.A.C. (BPJ)
Specific Conductance	umhos/ cm	62-4.070, and 62-620.320, F.A.C. (BPJ)
Turbidity	NTU	62-4.070, and 62-620.320, F.A.C. (BPJ)
Nitrogen, Ammonia, Total (as N)	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Ammonia, Total Unionized (as NH_3)	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Ammonium ion (NH_4^+)	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Nitrite plus Nitrate, Total (as N)	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Nitrogen, Kjeldahl, Total (as N)	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Nitrogen, Total	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Phosphate, Ortho (as PO_4)	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Phosphorous, Total	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Chlorophyll *a*	ug/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Copper, Total Recoverable	ug/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Iron, Total Recoverable	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Zinc, Total Recoverable	ug/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Boron, Total Recoverable	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Chlorides (as Cl)	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Magnesium, Total Recoverable	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Sodium, Total	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Sulfate, Total	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Tritium	pCi/L	62-4.070, and 62-620.320, F.A.C. (BPJ)

d. Porewater Monitoring

Table II.7 Porewater Monitoring Locations (Surface Water Monitoring Group D-02A)

During the period of operation authorized by this permit, the permittee shall sample porewater (free water present in sediments) from coastal marine wetlands north, east, and south of the CCS from locations described below in accordance with the protocols set forth in FPL's Quality Assurance Project Plan dated 2013:

Porewater Monitoring ID	Description of Monitoring Location	Latitude			Longitude		
PW M1-2	Coastal marine wetlands; ½ mile north of power block	25	26	49.8	80	19	57.7
PW M2-2	Coastal marine wetlands; east of CCS, 2 miles south of power block	25	24	18.8	80	19	47.6
PW M3-2	Coastal marine wetlands; east of CCS, 3.4 miles south of power block	25	23	4.2	80	19	40.6

PW M4-2	Coastal marine wetlands; southeast corner of CCS	25	21	16.8	80	19	44.9
PW M5-2	Coastal marine wetlands; south of CCS	25	20	56	80	20	33
PW M6-1	Coastal marine wetlands; west of Card Sound Road (background location)	25	17	40.1	80	23	46.8

Table II.8 Parameters monitored in Porewater

Parameter	Units	Sample Type	Monitoring Frequency
Temperature	Deg F	Grab	Semi-Annually
pH	s.u.	Grab	Semi-Annually
Specific Conductance	µmhos/cm	Grab	Semi-Annually
Salinity	PSU	Grab	Semi-Annually
Fluid Density	g/cm^3	Grab	Semi-Annually
Solids, Total Dissolved (TDS)	mg/L	Grab	Semi-Annually
Chloride (as Cl)	mg/L	Grab	Semi-Annually
Sodium, Total	mg/L	Grab	Semi-Annually
Calcium, Total	mg/L	Grab	Semi-Annually
Potassium, Total	mg/L	Grab	Semi-Annually
Boron, Total Recoverable	mg/L	Grab	Semi-Annually
Copper, Total Recoverable	ug/L	Grab	Semi-Annually

Iron, Total Recoverable	mg/L	Grab	Semi-Annually
Zinc, Total Recoverable	ug/L	Grab	Semi-Annually
Magnesium, Total Recoverable	mg/L	Grab	Semi-Annually
Sulfate, Total	mg/L	Grab	Semi-Annually
Tritium	pCi/L	Grab	Semi-Annually
Nitrogen, Ammonia, Total (as N)	mg/L	Grab	Semi-Annually
Ammonium ion (as NH_4)	mg/L	Grab	Semi-Annually
Ammonia, Total Unionized (as NH_3)	mg/L	Grab	Semi-Annually
Nitrite plus Nitrate, Total (as N)	mg/L	Grab	Semi-Annually
Nitrogen, Kjeldahl, Total (as N)	mg/L	Grab	Semi-Annually
Nitrogen, Total (as N)	mg/L	Grab	Semi-Annually
Phosphorus, Total (as P)	mg/L	Grab	Semi-Annually
Phosphate, Ortho (as PO_4)	mg/L	Grab	Semi-Annually

2. NEW PERMIT CONDITIONS

a. Nutrient Monitoring and Annual Reporting

The draft permit requires FPL to submit an annual nutrient monitoring summary report based on at least 24 months of groundwater, surface water, and CCS monitoring data to the Department. The report is to be submitted by ~~November~~ *August 31st* of each year, commencing in the third year following permit issuance. Where required by Chapter 471 (P.E.) or Chapter 492 (P.G.), Florida Statute, applicable portions of the report must be signed and sealed by the professional(s) who prepared them. The report is required to include by station and depth where specified:

a. Annual geometric mean (AGM) concentrations by nutrient parameter;
b. Arithmetic mean;
c. Percentiles including 25th, 75th, and 90th, number of samples collected by parameter; and

d. Evaluation of trends over the period of record by parameter.

b. Impoundment Conditions

FPL is required to properly operate and maintain all treatment and control facilities used to achieve compliance with this permit. Impoundments, including the CCS, used to treat or store wastewater are considered to be treatment and control facilities and are subject to the operation and maintenance requirements in this permit.

The permit includes new requirements to address impoundment construction, operation, and maintenance, including periodic inspections by trained personnel who are knowledgeable in impoundment design and safety. In addition, annual inspections by qualified responsible officials are required. Increased monitoring is required after large precipitation events, when there is an increased stress to impoundments and a greater potential for impacts on integrity. In response to any changes, such as cracks, erosion, bulges, and changes in seepage that may compromise their integrity, FPL is also required to respond in a timely manner. The permit requires documenting the results of the annual inspections and reporting the remedial activities taken, as well as timely reporting of changes to integrity and associated corrective actions.

The permittee shall take actions that will allow the thermal efficiency of the CCS to achieve a minimum annual average of 70 percent. The CCS shall be monitored at an annual average of its thermal efficiency determined, as is prescribed in the Turkey Point Thermal Efficiency Plan. The findings of each inspection including thermal efficiency shall be documented in a written annual inspection report as described in permit condition VIII.G.1.

c. Best Management Practices Plan

FPL is required to develop and implement a Best Management Practices Plan (Plan) to prevent or minimize the generation and the potential for the release of pollutants (including mercury per Rule 62-304.900, F.A.C., copper, iron, zinc, and nutrients) from facility operations (including spillage, leaks, and material and waste handling and storage activities) to industrial wastewater and stormwater in the CCS. FPL must develop and implement provisions of the Plan in accordance with Section VII of the permit.

e. Monitoring

The draft permit requires FPL to monitor groundwater, surface water, and porewater (see Figure 6). Groundwater monitoring consists of an existing network of sixty-five monitoring wells (see Figure 9). The Biscayne aquifer will be monitored both laterally and vertically, with monitoring wells set in shallow, intermediate and deep zones. As shown in Figure 9, the network includes groundwater monitoring wells located in Biscayne Bay, the CCS, near the facility perimeter, and westward, or inland, of the facility.

The surface watering monitoring consists of 20 monitoring sites – six in canals adjacent to the CCS, seven within the CCS, and seven in Biscayne Bay (see Figure 7). The previous permit included one of the monitoring sites in the CCS. The other nineteen monitoring sites are existing from other monitoring programs, and were selected to be included in this draft permit. Parameters include temperature, total suspended solids, pH, salinity, specific conductance, copper, iron and zinc.

Porewater monitoring consists of six sites located in coastal mangroves (see Figure 8). One site is located to establish background conditions. The other five are located to establish water quality conditions north, east and south of the CCS. The six porewater sites are existing from other monitoring programs, and were selected to be included in this draft permit. Parameters monitored at the porewater and surface water sites are the same. The draft permit requires FPL to take action to lower copper, iron, zinc and nitrate and nitrite in the CCS water if the levels reach certain thresholds.

3. CONSENT ORDER (OGC File No. 16-0241)

On June 20, 2016, FPL entered into a Consent Order (CO) with the Department to resolve a Notice of Violation (NOV) dated April 25, 2016. The CO ~~finds~~ *found* that elevated salinity levels in the CCS cause, or at a minimum contribute to, hypersaline discharges into the groundwater. *The CO also found that* ~~T~~*t*he CCS ~~is~~ *was* the major continuing cause of the westward movement of the saltwater interface (the intersection of Class G-II and G-III groundwaters), and that the discharge of hypersaline water contributes to saltwater intrusion. (The phrase "hypersaline" as used in the CO means water that exceeds 19,000 mg/L of chlorides). *The CO found that* ~~S~~*s*altwater intrusion into the area west of the CCS ~~is~~ *was* impairing the reasonable and beneficial use of adjacent G-II groundwater in that area. The CO stipulates remedial actions and timelines for achieving compliance with the following objectives:

a. cease discharges from the CCS that impair the reasonable and beneficial use of the adjacent Class G-II ground waters to the west of the CCS in violation of Condition I.1 (formerly Condition IV.1) of the Permit and Rule 62-520.400, F.A.C.;

b. prevent releases of groundwater from the CCS to surface waters connected to Biscayne Bay that result in exceedances of surface water quality standards; and

c. provide mitigation for impacts related to the historic operation of the CCS, including but not limited to the hypersaline plume and its influence on the saltwater interface.

After FPL has demonstrated to the Department that it has fulfilled the requirements of the CO, all requirements of the CO will be terminated except for the requirement to maintain the average annual salinity of the CCS at or below 34 practical salinity until an average annual salinity of the CCS is designated in a Department permit.

4. THE ADMINISTRATIVE RECORD

The administrative record including application, draft permit, fact sheet, public notice (after release), comments received and additional information is available for public inspection during normal business hours at the location specified in Section 8. Copies will be provided at a minimal charge per page.

5. PROPOSED SCHEDULE FOR PERMIT ISSUANCE

Draft Permit and Public Notice to Applicant and U.S. Environmental Protection Agency (EPA)	January 2, 2019
Public Comment Period	Beginning: February 1, 2019 Ending: March 3, 2019
Notice of Intent to Issue	April 2, 2019
Notice of Permit Issuance	April 23, 2019

6. DEPARTMENTOF ENVIRONMENTAL PROTECTION CONTACT

Additional information concerning the permit and proposed schedule for permit issuance may be obtained during normal business hours from:

Marc Harris, P.E.
Department of Environmental Protection
Bob Martinez Center
2600 Blair Stone Road, Mail Station 3545
Tallahassee, Florida 32399-2400
Telephone Number: (850) 245-8589

Fax Number: (850) 245-8669

7. PROCEDURES FOR THE FORMULATION OF FINAL DETERMINATIONS

a. Public Comment Period

The Department of Environmental Protection proposes to issue a wastewater facility permit to this applicant subject to the aforementioned effluent limitations and conditions. This decision is tentative and open to comment from the public.

Interested persons are invited to submit written comments regarding permit issuance on the draft permit limitations and conditions to the following address:

Department of Environmental Protection
2600 Blair Stone Road
Mail Station 3545
Tallahassee, Florida 32399-2400
Attn.: Marc Harris, P.E.

All comments received within 30 days following the date of public notice, pursuant to Rule 62-620.550, F.A.C., will be considered in the formulation of the final decision with regard to permit issuance.

Any interested person may submit written comments on the Department's proposed permitting decision or may submit a written request for a public meeting to the address specified above, in accordance with Rule 62-620.555, F.A.C. The comments or request for a public meeting must contain the information set forth below and must be received in the above address of the Department within 30 days of receipt or publication of the public notice. Failure to submit comments or request a public meeting within this time period will constitute a waiver of any right such person may have to submit comments or request a public meeting under Rule 62-620.555, F.A.C.

The comments or request for a public meeting shall contain the following information:

(1) The commenter's name, address and telephone number, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed;
(2) A statement of how and when notice of the draft permit was received;
(3) A description of any changes the commenter proposes for the draft permit;
(4) A full explanation of the factual and legal reasons for each proposed change to the draft permit; and
(5) A request that a public meeting be scheduled (if applicable) including a statement of the nature of the issues proposed to be raised at the meeting.

b. Public Meeting

The Department will hold a public meeting if there is a significant degree of public interest in the draft permit or if it determines that useful information and data may be obtained thereby. Public notice of such a meeting shall be published by the applicant at least 30 days prior to the meeting.

If a public meeting is scheduled the public comment period is extended until the close of the public meeting. If a public meeting is held any person may submit oral or written statements and data at the meeting on the Department's proposed action.

c. Issuance of the Permit

The Department will make its decision regarding permit issuance after consideration of all written comments, including comments from the EPA on surface water discharge (NPDES) aspects of the draft or proposed permit; the requirements of Chapter 403, F.S., and appropriate rules; and, if a public meeting is held, after consideration of all comments, statements and data presented at the public meeting. The Department will respond to all significant comments in writing. The Department's response to significant comments will be included in the administrative record of the permit and will be available for public inspection at the above address of the Department.

Unless a request for an administrative hearing, or an extension of time to file a petition for an administrative hearing, pursuant to Chapter 120, F.S., as indicated in d. below, is granted, the Department will take final agency action by issuing the permit or denying the permit application. If an administrative hearing is convened, final agency action will be based on the outcome of the hearing.

d. Administrative Hearing

A person whose substantial interests are affected by the Department's proposed permitting decision has the opportunity to petition for an administrative proceeding (hearing) to challenge the Department's decision in accordance with Section 120.57, F.S.

An administrative hearing is an evidentiary proceeding in which evidence is presented by testimony and exhibits before an independent hearing officer. The result of an administrative hearing is the issuance of the hearing officer's recommended order to the Department, including the hearing officer's findings of fact, based on the evidence presented at the hearing. The Department will issue a final order, granting or denying the permit, based on the hearing officer's recommended order.

The petition for an administrative hearing must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Tallahassee, Florida 32399-3000, within 14 days of publication of notice of agency action or within 14 days of personal receipt of notice of agency action, whichever occurs first. The petitioner is to mail a copy of the petition to the applicant at the time of filing. Failure to file a petition within this time period will constitute a waiver of any right such person may have to request an administrative determination (hearing) under section 120.57, F.S. The petition is to contain the following information:

(1) The name, address and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed;
(2) A statement of how and when each petitioner received notice of the Department's action or proposed action;
(3) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action;
(4) A statement of the material facts which the petitioner contends warrant reversal or modification of the Department's action or proposed action;
(5) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and
(6) A statement of the relief sought by the petitioner, stating precisely the action the petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in the notice of agency action. Persons whose substantial interests will be affected by any decision of the Department on the application have the right to petition to become a party to the proceeding, regardless of their agreement or disagreement with the Department's proposed action indicated in the notice of agency action.

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed submit this report to: http://www.fldepportal.com/go/

PERMITTEE NAME: FPL
MAILING ADDRESS: 700 Universe Blvd
Juno Beach, Florida 33408-

FACILITY: FPL Turkey Point Plant
LOCATION: 9700 SW 344th St

Homestead, FL 33035-1800

COUNTY: Miami-Dade
OFFICE: Tallahassee

PERMIT NUMBER: FL0001562-012-IW1N

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: D-01A
MONITORING GROUP DESCRIPTION: A new permitted series of surface water monitoring sites in Biscayne Bay, L-31E canal, S-20 canal and Card Sound canal that monitors surface waters.

REPORT FREQUENCY: Monthly
PROGRAM: Industrial

RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: ____________________ To: ____________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Temperature (F), Water (Top)	Sample Measurement										
PARM Code 00011 6 Mon. Site No. SWD-2	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Bottom)	Sample Measurement										
PARM Code 00011 P Mon. Site No. SWD-2	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Top)	Sample Measurement										
PARM Code 00011 Q Mon. Site No. SWD-3	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Bottom)	Sample Measurement										
PARM Code 00011 R Mon. Site No. SWD-3	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Top)	Sample Measurement										
PARM Code 00011 S Mon. Site No. SWD-4	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Bottom)	Sample Measurement										
PARM Code 00011 T Mon. Site No. SWD-4	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (mm/dd/yyyy)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

DEP Form 62-620.910(10), Effective Nov. 29, 1994

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant | MONITORING GROUP NUMBER: D-01A | PERMIT NUMBER: FL0001562-012-IW1N
MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Temperature (F), Water (Top)	Sample Measurement										
PARM Code 00011 U Mon. Site No. SWD-5	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Bottom)	Sample Measurement										
PARM Code 00011 V Mon. Site No. SWD-5	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Top)	Sample Measurement										
PARM Code 00011 W Mon. Site No. SWD-6	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Bottom)	Sample Measurement										
PARM Code 00011 1 Mon. Site No. SWD-6	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Top)	Sample Measurement										
PARM Code 00011 5 Mon. Site No. SWD-7	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Bottom)	Sample Measurement										
PARM Code 00011 A Mon. Site No. SWD-7	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Top)	Sample Measurement										
PARM Code 00011 B Mon. Site No. SWD-8	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Bottom)	Sample Measurement										
PARM Code 00011 G Mon. Site No. SWD-8	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Top)	Sample Measurement										
PARM Code 00011 7 Mon. Site No. SWD-9	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Bottom)	Sample Measurement										
PARM Code 00011 I Mon. Site No. SWD-9	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Temperature (F), Water (Top)	Sample Measurement										
PARM Code 00011 J Mon. Site No. SWD-10	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Bottom)	Sample Measurement										
PARM Code 00011 K Mon. Site No. SWD-10	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Top)	Sample Measurement										
PARM Code 00011 Y Mon. Site No. SWD-11	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Bottom)	Sample Measurement										
PARM Code 00011 0 Mon. Site No. SWD-11	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Top)	Sample Measurement										
PARM Code 00011 2 Mon. Site No. SWD-12	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Bottom)	Sample Measurement										
PARM Code 00011 3 Mon. Site No. SWD-12	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Salinity (Top)	Sample Measurement										
PARM Code 00480 6 Mon. Site No. SWD-8	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ppt		Monthly	In Situ
Salinity (Bottom)	Sample Measurement										
PARM Code 00480 P Mon. Site No. SWD-8	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ppt		Monthly	In Situ
Salinity (Top)	Sample Measurement										
PARM Code 00480 Q Mon. Site No. SWD-9	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ppt		Monthly	In Situ
Salinity (Bottom)	Sample Measurement										
PARM Code 00480 R Mon. Site No. SWD-9	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ppt		Monthly	In Situ

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Salinity (Top)	Sample Measurement										
PARM Code 00480 S Mon. Site No. SWD-10	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ppt		Monthly	In Situ
Salinity (Bottom)	Sample Measurement										
PARM Code 00480 T Mon. Site No. SWD-10	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ppt		Monthly	In Situ
Salinity (Top)	Sample Measurement										
PARM Code 00480 U Mon. Site No. SWD-11	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ppt		Monthly	In Situ
Salinity (Bottom)	Sample Measurement										
PARM Code 00480 V Mon. Site No. SWD-11	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ppt		Monthly	In Situ
Salinity (Top)	Sample Measurement										
PARM Code 00480 W Mon. Site No. SWD-12	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ppt		Monthly	In Situ
Salinity (Bottom)	Sample Measurement										
PARM Code 00480 1 Mon. Site No. SWD-12	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ppt		Monthly	In Situ
Salinity	Sample Measurement										
PARM Code 00480 5 Mon. Site No. SWD-1	Permit Requirement						Report (Mo.Avg.)	ppt		Monthly	Calculated
Chloride (as Cl)	Sample Measurement										
PARM Code 00940 6 Mon. Site No. SWD-1	Permit Requirement						Report (Mo.Avg.)	mg/L		Monthly	Calculated

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed submit this report to: http://www.fldepportal.com/go/

PERMITTEE NAME: FPL
MAILING ADDRESS: 700 Universe Blvd
Juno Beach, Florida 33408-

FACILITY: FPL Turkey Point Plant
LOCATION: 9700 SW 344th St

Homestead, FL 33035-1800

COUNTY: Miami-Dade
OFFICE: Tallahassee

PERMIT NUMBER: FL0001562-012-IW1N

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: D-01A
MONITORING GROUP DESCRIPTION: A new permitted series of surface water monitoring sites in Biscayne Bay, L-31E canal, S-20 canal and Card Sound canal that monitors surface waters.

REPORT FREQUENCY: Quarterly
PROGRAM: Industrial

RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: ____________________ To: ____________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
pH (Top)	Sample Measurement										
PARM Code 00400 6 Mon. Site No. SWD-2	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Bottom)	Sample Measurement										
PARM Code 00400 P Mon. Site No. SWD-2	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Top)	Sample Measurement										
PARM Code 00400 Q Mon. Site No. SWD-3	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Bottom)	Sample Measurement										
PARM Code 00400 R Mon. Site No. SWD-3	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Top)	Sample Measurement										
PARM Code 00400 S Mon. Site No. SWD-4	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Bottom)	Sample Measurement										
PARM Code 00400 T Mon. Site No. SWD-4	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (mm/dd/yyyy)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
pH (Top)	Sample Measurement										
PARM Code 00400 U Mon. Site No. SWD-5	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Bottom)	Sample Measurement										
PARM Code 00400 V Mon. Site No. SWD-5	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Top)	Sample Measurement										
PARM Code 00400 W Mon. Site No. SWD-6	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Bottom)	Sample Measurement										
PARM Code 00400 1 Mon. Site No. SWD-6	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Top)	Sample Measurement										
PARM Code 00400 5 Mon. Site No. SWD-7	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Bottom)	Sample Measurement										
PARM Code 00400 A Mon. Site No. SWD-7	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Top)	Sample Measurement										
PARM Code 00400 B Mon. Site No. SWD-8	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Bottom)	Sample Measurement										
PARM Code 00400 G Mon. Site No. SWD-8	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Top)	Sample Measurement										
PARM Code 00400 7 Mon. Site No. SWD-9	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Bottom)	Sample Measurement										
PARM Code 00400 I Mon. Site No. SWD-9	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
pH (Top)	Sample Measurement										
PARM Code 00400 J Mon. Site No. SWD-10	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Bottom)	Sample Measurement										
PARM Code 00400 K Mon. Site No. SWD-10	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Top)	Sample Measurement										
PARM Code 00400 Y Mon. Site No. SWD-11	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Bottom)	Sample Measurement										
PARM Code 00400 0 Mon. Site No. SWD-11	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Top)	Sample Measurement										
PARM Code 00400 2 Mon. Site No. SWD-12	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Bottom)	Sample Measurement										
PARM Code 00400 3 Mon. Site No. SWD-12	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
Solids, Total Dissolved (TDS) (Top)	Sample Measurement										
PARM Code 70295 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Bottom)	Sample Measurement										
PARM Code 70295 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Top)	Sample Measurement										
PARM Code 70295 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Bottom)	Sample Measurement										
PARM Code 70295 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Solids, Total Dissolved (TDS) (Top)	Sample Measurement										
PARM Code 70295 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Bottom)	Sample Measurement										
PARM Code 70295 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Top)	Sample Measurement										
PARM Code 70295 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Bottom)	Sample Measurement										
PARM Code 70295 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Top)	Sample Measurement										
PARM Code 70295 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Bottom)	Sample Measurement										
PARM Code 70295 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Top)	Sample Measurement										
PARM Code 70295 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Bottom)	Sample Measurement										
PARM Code 70295 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Top)	Sample Measurement										
PARM Code 70295 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Bottom)	Sample Measurement										
PARM Code 70295 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Solids, Total Dissolved (TDS) (Top)	Sample Measurement										
PARM Code 70295 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Bottom)	Sample Measurement										
PARM Code 70295 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Top)	Sample Measurement										
PARM Code 70295 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Bottom)	Sample Measurement										
PARM Code 70295 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Top)	Sample Measurement										
PARM Code 70295 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Bottom)	Sample Measurement										
PARM Code 70295 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Top)	Sample Measurement										
PARM Code 70295 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Bottom)	Sample Measurement										
PARM Code 70295 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Specific Conductance (Top)	Sample Measurement										
PARM Code 00095 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Bottom)	Sample Measurement										
PARM Code 00095 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ

ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ______________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Specific Conductance (Top)	Sample Measurement										
PARM Code 00095 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Bottom)	Sample Measurement										
PARM Code 00095 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Top)	Sample Measurement										
PARM Code 00095 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Bottom)	Sample Measurement										
PARM Code 00095 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Top)	Sample Measurement										
PARM Code 00095 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Bottom)	Sample Measurement										
PARM Code 00095 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Top)	Sample Measurement										
PARM Code 00095 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Bottom)	Sample Measurement										
PARM Code 00095 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Top)	Sample Measurement										
PARM Code 00095 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Bottom)	Sample Measurement										
PARM Code 00095 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant MONITORING GROUP NUMBER: D-01A PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Specific Conductance (Top)	Sample Measurement										
PARM Code 00095 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Bottom)	Sample Measurement										
PARM Code 00095 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Top)	Sample Measurement										
PARM Code 00095 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Bottom)	Sample Measurement										
PARM Code 00095 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Top)	Sample Measurement										
PARM Code 00095 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Bottom)	Sample Measurement										
PARM Code 00095 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Top)	Sample Measurement										
PARM Code 00095 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Bottom)	Sample Measurement										
PARM Code 00095 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Top)	Sample Measurement										
PARM Code 00095 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Bottom)	Sample Measurement										
PARM Code 00095 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant | MONITORING GROUP NUMBER: D-01A | PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Turbidity (Top)	Sample Measurement										
PARM Code 00070 6 Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	NTU		Quarterly	Grab
Turbidity (Bottom)	Sample Measurement										
PARM Code 00070 P Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	NTU		Quarterly	Grab
Turbidity (Top)	Sample Measurement										
PARM Code 00070 Q Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	NTU		Quarterly	Grab
Turbidity (Bottom)	Sample Measurement										
PARM Code 00070 R Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	NTU		Quarterly	Grab
Turbidity (Top)	Sample Measurement										
PARM Code 00070 S Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	NTU		Quarterly	Grab
Turbidity (Bottom)	Sample Measurement										
PARM Code 00070 T Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	NTU		Quarterly	Grab
Turbidity (Top)	Sample Measurement										
PARM Code 00070 U Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	NTU		Quarterly	Grab
Turbidity (Bottom)	Sample Measurement										
PARM Code 00070 V Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	NTU		Quarterly	Grab
Turbidity (Top)	Sample Measurement										
PARM Code 00070 W Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	NTU		Quarterly	Grab
Turbidity (Bottom)	Sample Measurement										
PARM Code 00070 1 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	NTU		Quarterly	Grab

ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant
MONITORING GROUP NUMBER: D-01A
PERMIT NUMBER: FL0001562-012-IW1N
MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrogen, Ammonia, Total (as N) (Top)	Sample Measurement										
PARM Code 00610 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00610 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Top)	Sample Measurement										
PARM Code 00610 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00610 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Top)	Sample Measurement										
PARM Code 00610 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00610 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Top)	Sample Measurement										
PARM Code 00610 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00610 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Top)	Sample Measurement										
PARM Code 00610 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00610 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: _______________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrogen, Ammonia, Total (as N) (Top)	Sample Measurement										
PARM Code 00610 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00610 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Top)	Sample Measurement										
PARM Code 00610 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00610 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Top)	Sample Measurement										
PARM Code 00610 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00610 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Top)	Sample Measurement										
PARM Code 00610 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00610 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Top)	Sample Measurement										
PARM Code 00610 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00610 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrogen, Ammonia, Total (as N) (Top)	Sample Measurement										
PARM Code 00610 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00610 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Ammonia, Unionized (as NH3) (Top)	Sample Measurement										
PARM Code 00619 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Bottom)	Sample Measurement										
PARM Code 00619 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Top)	Sample Measurement										
PARM Code 00619 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Bottom)	Sample Measurement										
PARM Code 00619 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Top)	Sample Measurement										
PARM Code 00619 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Bottom)	Sample Measurement										
PARM Code 00619 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Top)	Sample Measurement										
PARM Code 00619 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Bottom)	Sample Measurement										
PARM Code 00619 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated

ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Ammonia, Unionized (as NH3) (Top)	Sample Measurement										
PARM Code 00619 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Bottom)	Sample Measurement										
PARM Code 00619 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Top)	Sample Measurement										
PARM Code 00619 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Bottom)	Sample Measurement										
PARM Code 00619 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Top)	Sample Measurement										
PARM Code 00619 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Bottom)	Sample Measurement										
PARM Code 00619 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Top)	Sample Measurement										
PARM Code 00619 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Bottom)	Sample Measurement										
PARM Code 00619 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Top)	Sample Measurement										
PARM Code 00619 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Bottom)	Sample Measurement										
PARM Code 00619 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: _______________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Ammonia, Unionized (as NH3) (Top)	Sample Measurement										
PARM Code 00619 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Top)	Sample Measurement										
PARM Code 00619 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Bottom)	Sample Measurement										
PARM Code 00619 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Bottom)	Sample Measurement										
PARM Code 00619 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Top)	Sample Measurement										
PARM Code 71845 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Bottom)	Sample Measurement										
PARM Code 71845 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Top)	Sample Measurement										
PARM Code 71845 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Bottom)	Sample Measurement										
PARM Code 71845 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Top)	Sample Measurement										
PARM Code 71845 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Bottom)	Sample Measurement										
PARM Code 71845 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant | MONITORING GROUP NUMBER: D-01A | PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________ To: ____________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrogen, Ammonia, Total (as NH4) (Top)	Sample Measurement										
PARM Code 71845 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Bottom)	Sample Measurement										
PARM Code 71845 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Top)	Sample Measurement										
PARM Code 71845 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Bottom)	Sample Measurement										
PARM Code 71845 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Top)	Sample Measurement										
PARM Code 71845 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Bottom)	Sample Measurement										
PARM Code 71845 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Top)	Sample Measurement										
PARM Code 71845 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Bottom)	Sample Measurement										
PARM Code 71845 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Top)	Sample Measurement										
PARM Code 71845 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Bottom)	Sample Measurement										
PARM Code 71845 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________ To: ____________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrogen, Ammonia, Total (as NH4) (Top)	Sample Measurement										
PARM Code 71845 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Bottom)	Sample Measurement										
PARM Code 71845 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Top)	Sample Measurement										
PARM Code 71845 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Bottom)	Sample Measurement										
PARM Code 71845 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Top)	Sample Measurement										
PARM Code 71845 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Bottom)	Sample Measurement										
PARM Code 71845 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrite plus Nitrate, Total 1 det. (as N) (Top)	Sample Measurement										
PARM Code 00630 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Bottom)	Sample Measurement										
PARM Code 00630 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Top)	Sample Measurement										
PARM Code 00630 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Bottom)	Sample Measurement										
PARM Code 00630 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant | MONITORING GROUP NUMBER: D-01A | PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrite plus Nitrate, Total 1 det. (as N) (Top)	Sample Measurement										
PARM Code 00630 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Bottom)	Sample Measurement										
PARM Code 00630 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Top)	Sample Measurement										
PARM Code 00630 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Bottom)	Sample Measurement										
PARM Code 00630 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Top)	Sample Measurement										
PARM Code 00630 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Bottom)	Sample Measurement										
PARM Code 00630 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Top)	Sample Measurement										
PARM Code 00630 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Bottom)	Sample Measurement										
PARM Code 00630 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Top)	Sample Measurement										
PARM Code 00630 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Bottom)	Sample Measurement										
PARM Code 00630 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrite plus Nitrate, Total 1 det. (as N) (Top)	Sample Measurement										
PARM Code 00630 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Bottom)	Sample Measurement										
PARM Code 00630 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Top)	Sample Measurement										
PARM Code 00630 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Bottom)	Sample Measurement										
PARM Code 00630 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Top)	Sample Measurement										
PARM Code 00630 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Bottom)	Sample Measurement										
PARM Code 00630 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Top)	Sample Measurement										
PARM Code 00630 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Bottom)	Sample Measurement										
PARM Code 00630 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Top)	Sample Measurement										
PARM Code 00625 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00625 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrogen, Kjeldahl, Total (as N) (Top)	Sample Measurement										
PARM Code 00625 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00625 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Top)	Sample Measurement										
PARM Code 00625 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00625 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Top)	Sample Measurement										
PARM Code 00625 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00625 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Top)	Sample Measurement										
PARM Code 00625 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00625 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Top)	Sample Measurement										
PARM Code 00625 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00625 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant | MONITORING GROUP NUMBER: D-01A | PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrogen, Kjeldahl, Total (as N) (Top)	Sample Measurement										
PARM Code 00625 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00625 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Top)	Sample Measurement										
PARM Code 00625 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00625 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Top)	Sample Measurement										
PARM Code 00625 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00625 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Top)	Sample Measurement										
PARM Code 00625 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00625 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Top)	Sample Measurement										
PARM Code 00625 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00625 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrogen, Total (Top)	Sample Measurement										
PARM Code 00600 6 Mon. Site No. SWD-2	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Bottom)	Sample Measurement										
PARM Code 00600 P Mon. Site No. SWD-2	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Top)	Sample Measurement										
PARM Code 00600 Q Mon. Site No. SWD-3	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Bottom)	Sample Measurement										
PARM Code 00600 R Mon. Site No. SWD-3	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Top)	Sample Measurement										
PARM Code 00600 S Mon. Site No. SWD-4	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Bottom)	Sample Measurement										
PARM Code 00600 T Mon. Site No. SWD-4	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Top)	Sample Measurement										
PARM Code 00600 U Mon. Site No. SWD-5	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Bottom)	Sample Measurement										
PARM Code 00600 V Mon. Site No. SWD-5	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Top)	Sample Measurement										
PARM Code 00600 W Mon. Site No. SWD-6	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Bottom)	Sample Measurement										
PARM Code 00600 1 Mon. Site No. SWD-6	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrogen, Total (Top)	Sample Measurement										
PARM Code 00600 5 Mon. Site No. SWD-7	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Bottom)	Sample Measurement										
PARM Code 00600 A Mon. Site No. SWD-7	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Top)	Sample Measurement										
PARM Code 00600 B Mon. Site No. SWD-8	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Bottom)	Sample Measurement										
PARM Code 00600 G Mon. Site No. SWD-8	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Top)	Sample Measurement										
PARM Code 00600 7 Mon. Site No. SWD-9	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Bottom)	Sample Measurement										
PARM Code 00600 I Mon. Site No. SWD-9	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Top)	Sample Measurement										
PARM Code 00600 J Mon. Site No. SWD-10	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Bottom)	Sample Measurement										
PARM Code 00600 K Mon. Site No. SWD-10	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Top)	Sample Measurement										
PARM Code 00600 Y Mon. Site No. SWD-11	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Bottom)	Sample Measurement										
PARM Code 00600 0 Mon. Site No. SWD-11	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrogen, Total (Top)	Sample Measurement										
PARM Code 00600 2 Mon. Site No. SWD-12	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Bottom)	Sample Measurement										
PARM Code 00600 3 Mon. Site No. SWD-12	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Phosphate, Ortho (as PO4) (Top)	Sample Measurement										
PARM Code 00660 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Bottom)	Sample Measurement										
PARM Code 00660 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Top)	Sample Measurement										
PARM Code 00660 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Bottom)	Sample Measurement										
PARM Code 00660 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Top)	Sample Measurement										
PARM Code 00660 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Bottom)	Sample Measurement										
PARM Code 00660 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Top)	Sample Measurement										
PARM Code 00660 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Bottom)	Sample Measurement										
PARM Code 00660 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ______________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Phosphate, Ortho (as PO4) (Top)	Sample Measurement										
PARM Code 00660 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Bottom)	Sample Measurement										
PARM Code 00660 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Top)	Sample Measurement										
PARM Code 00660 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Bottom)	Sample Measurement										
PARM Code 00660 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Top)	Sample Measurement										
PARM Code 00660 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Bottom)	Sample Measurement										
PARM Code 00660 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Top)	Sample Measurement										
PARM Code 00660 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Bottom)	Sample Measurement										
PARM Code 00660 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Top)	Sample Measurement										
PARM Code 00660 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Bottom)	Sample Measurement										
PARM Code 00660 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant | MONITORING GROUP NUMBER: D-01A | PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Phosphate, Ortho (as PO4) (Top)	Sample Measurement										
PARM Code 00660 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Bottom)	Sample Measurement										
PARM Code 00660 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Top)	Sample Measurement										
PARM Code 00660 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Bottom)	Sample Measurement										
PARM Code 00660 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Top)	Sample Measurement										
PARM Code 00665 6 Mon. Site No. SWD-2	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Bottom)	Sample Measurement										
PARM Code 00665 P Mon. Site No. SWD-2	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Top)	Sample Measurement										
PARM Code 00665 Q Mon. Site No. SWD-3	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Bottom)	Sample Measurement										
PARM Code 00665 R Mon. Site No. SWD-3	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Top)	Sample Measurement										
PARM Code 00665 S Mon. Site No. SWD-4	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Bottom)	Sample Measurement										
PARM Code 00665 T Mon. Site No. SWD-4	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab

ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Phosphorus, Total (as P) (Top)	Sample Measurement										
PARM Code 00665 U Mon. Site No. SWD-5	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Bottom)	Sample Measurement										
PARM Code 00665 V Mon. Site No. SWD-5	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Top)	Sample Measurement										
PARM Code 00665 W Mon. Site No. SWD-6	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Bottom)	Sample Measurement										
PARM Code 00665 1 Mon. Site No. SWD-6	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Top)	Sample Measurement										
PARM Code 00665 5 Mon. Site No. SWD-7	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Bottom)	Sample Measurement										
PARM Code 00665 A Mon. Site No. SWD-7	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Top)	Sample Measurement										
PARM Code 00665 B Mon. Site No. SWD-8	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Bottom)	Sample Measurement										
PARM Code 00665 G Mon. Site No. SWD-8	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Top)	Sample Measurement										
PARM Code 00665 7 Mon. Site No. SWD-9	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Bottom)	Sample Measurement										
PARM Code 00665 I Mon. Site No. SWD-9	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Phosphorus, Total (as P) (Top)	Sample Measurement										
PARM Code 00665 J Mon. Site No. SWD-10	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Bottom)	Sample Measurement										
PARM Code 00665 K Mon. Site No. SWD-10	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Top)	Sample Measurement										
PARM Code 00665 Y Mon. Site No. SWD-11	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Bottom)	Sample Measurement										
PARM Code 00665 0 Mon. Site No. SWD-11	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Top)	Sample Measurement										
PARM Code 00665 2 Mon. Site No. SWD-12	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Bottom)	Sample Measurement										
PARM Code 00665 3 Mon. Site No. SWD-12	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Chlorophyll a (Top)	Sample Measurement										
PARM Code 32230 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Bottom)	Sample Measurement										
PARM Code 32230 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Top)	Sample Measurement										
PARM Code 32230 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Bottom)	Sample Measurement										
PARM Code 32230 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Chlorophyll a (Top)	Sample Measurement										
PARM Code 32230 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Bottom)	Sample Measurement										
PARM Code 32230 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Top)	Sample Measurement										
PARM Code 32230 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Bottom)	Sample Measurement										
PARM Code 32230 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Top)	Sample Measurement										
PARM Code 32230 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Bottom)	Sample Measurement										
PARM Code 32230 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Top)	Sample Measurement										
PARM Code 32230 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Bottom)	Sample Measurement										
PARM Code 32230 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Top)	Sample Measurement										
PARM Code 32230 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Bottom)	Sample Measurement										
PARM Code 32230 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Chlorophyll a (Top)	Sample Measurement										
PARM Code 32230 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Bottom)	Sample Measurement										
PARM Code 32230 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Top)	Sample Measurement										
PARM Code 32230 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Bottom)	Sample Measurement										
PARM Code 32230 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Top)	Sample Measurement										
PARM Code 32230 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Bottom)	Sample Measurement										
PARM Code 32230 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Top)	Sample Measurement										
PARM Code 32230 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Bottom)	Sample Measurement										
PARM Code 32230 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Top)	Sample Measurement										
PARM Code 01119 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01119 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Copper, Total Recoverable (Top)	Sample Measurement										
PARM Code 01119 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01119 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Top)	Sample Measurement										
PARM Code 01119 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01119 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Top)	Sample Measurement										
PARM Code 01119 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01119 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Top)	Sample Measurement										
PARM Code 01119 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01119 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Top)	Sample Measurement										
PARM Code 01119 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01119 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________ To: ____________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Copper, Total Recoverable (Top)	Sample Measurement										
PARM Code 01119 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01119 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Top)	Sample Measurement										
PARM Code 01119 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01119 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Top)	Sample Measurement										
PARM Code 01119 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01119 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Top)	Sample Measurement										
PARM Code 01119 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01119 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Top)	Sample Measurement										
PARM Code 01119 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01119 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________ To: ____________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Iron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00980 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00980 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00980 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00980 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00980 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00980 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00980 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00980 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00980 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00980 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Iron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00980 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00980 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00980 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00980 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00980 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00980 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00980 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00980 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00980 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00980 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Iron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00980 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00980 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Zinc, Total Recoverable (Top)	Sample Measurement										
PARM Code 01094 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01094 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Top)	Sample Measurement										
PARM Code 01094 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01094 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Top)	Sample Measurement										
PARM Code 01094 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01094 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Top)	Sample Measurement										
PARM Code 01094 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01094 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: _______________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Zinc, Total Recoverable (Top)	Sample Measurement										
PARM Code 01094 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01094 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Top)	Sample Measurement										
PARM Code 01094 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01094 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Top)	Sample Measurement										
PARM Code 01094 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01094 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Top)	Sample Measurement										
PARM Code 01094 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01094 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Top)	Sample Measurement										
PARM Code 01094 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01094 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: _______________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Zinc, Total Recoverable (Top)	Sample Measurement										
PARM Code 01094 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01094 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Top)	Sample Measurement										
PARM Code 01094 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01094 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Boron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00999 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00999 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00999 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00999 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00999 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00999 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________ To: ____________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Boron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00999 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00999 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00999 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00999 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00999 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00999 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00999 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00999 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00999 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00999 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

ISSUANCE/REISSUANCE DATE:

DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Boron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00999 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00999 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00999 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00999 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00999 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00999 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Top)	Sample Measurement										
PARM Code 00940 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Bottom)	Sample Measurement										
PARM Code 00940 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Top)	Sample Measurement										
PARM Code 00940 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Bottom)	Sample Measurement										
PARM Code 00940 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant | MONITORING GROUP NUMBER: D-01A | PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Chloride (as Cl) (Top)	Sample Measurement										
PARM Code 00940 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Bottom)	Sample Measurement										
PARM Code 00940 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Top)	Sample Measurement										
PARM Code 00940 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Bottom)	Sample Measurement										
PARM Code 00940 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Top)	Sample Measurement										
PARM Code 00940 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Bottom)	Sample Measurement										
PARM Code 00940 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Top)	Sample Measurement										
PARM Code 00940 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Bottom)	Sample Measurement										
PARM Code 00940 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Top)	Sample Measurement										
PARM Code 00940 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Bottom)	Sample Measurement										
PARM Code 00940 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Chloride (as Cl) (Top)	Sample Measurement										
PARM Code 00940 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Bottom)	Sample Measurement										
PARM Code 00940 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Top)	Sample Measurement										
PARM Code 00940 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Bottom)	Sample Measurement										
PARM Code 00940 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Top)	Sample Measurement										
PARM Code 00940 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Bottom)	Sample Measurement										
PARM Code 00940 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Top)	Sample Measurement										
PARM Code 00940 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Bottom)	Sample Measurement										
PARM Code 00940 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00921 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00921 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Magnesium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00921 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00921 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00921 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00921 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00921 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00921 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00921 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00921 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00921 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00921 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________ To: ____________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Magnesium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00921 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00921 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00921 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00921 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00921 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00921 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00921 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00921 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00921 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00921 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Sodium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00923 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00923 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00923 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00923 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00923 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00923 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00923 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00923 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00923 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00923 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant MONITORING GROUP NUMBER: D-01A PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Sodium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00923 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00923 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00923 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00923 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00923 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00923 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00923 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00923 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00923 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00923 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________ To: ____________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Sodium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00923 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00923 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Top)	Sample Measurement										
PARM Code 00945 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Bottom)	Sample Measurement										
PARM Code 00945 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Top)	Sample Measurement										
PARM Code 00945 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Bottom)	Sample Measurement										
PARM Code 00945 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Top)	Sample Measurement										
PARM Code 00945 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Bottom)	Sample Measurement										
PARM Code 00945 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Top)	Sample Measurement										
PARM Code 00945 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Bottom)	Sample Measurement										
PARM Code 00945 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant | MONITORING GROUP NUMBER: D-01A | PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________ To: ____________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Sulfate, Total (Top)	Sample Measurement										
PARM Code 00945 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Bottom)	Sample Measurement										
PARM Code 00945 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Top)	Sample Measurement										
PARM Code 00945 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Bottom)	Sample Measurement										
PARM Code 00945 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Top)	Sample Measurement										
PARM Code 00945 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Bottom)	Sample Measurement										
PARM Code 00945 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Top)	Sample Measurement										
PARM Code 00945 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Bottom)	Sample Measurement										
PARM Code 00945 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Top)	Sample Measurement										
PARM Code 00945 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Bottom)	Sample Measurement										
PARM Code 00945 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Sulfate, Total (Top)	Sample Measurement										
PARM Code 00945 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Bottom)	Sample Measurement										
PARM Code 00945 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Top)	Sample Measurement										
PARM Code 00945 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Bottom)	Sample Measurement										
PARM Code 00945 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Turbidity	Sample Measurement										
PARM Code 00070 5 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	NTU		Quarterly	Grab

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed submit this report to: http://www.fldepportal.com/go/

PERMITTEE NAME:	FPL	PERMIT NUMBER:	FL0001562-012-IW1N
MAILING ADDRESS:	700 Universe Blvd Juno Beach, Florida 33408-	LIMIT:	Final
		REPORT FREQUENCY:	Semi-annually
		CLASS SIZE:	MA
		PROGRAM:	Industrial
FACILITY:	FPL Turkey Point Plant	MONITORING GROUP NUMBER:	D-02A
LOCATION:	9700 SW 344th St Homestead, FL 33035-1800	MONITORING GROUP DESCRIPTION:	A new permitted series of porewater (free water present in sediments) monitoring sites in coastal marine wetlands north, east, and south of the facility s onsite CCS.
		RE-SUBMITTED DMR:	☐
		NO DISCHARGE FROM SITE:	☐
COUNTY:	Miami-Dade	MONITORING PERIOD	From: ____________________ To: ____________________
OFFICE:	Tallahassee		

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Temperature (F), Water	Sample Measurement										
PARM Code 00011 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	Deg F		Semi-Annually; twice per year	Grab
Temperature (F), Water	Sample Measurement										
PARM Code 00011 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	Deg F		Semi-Annually; twice per year	Grab
Temperature (F), Water	Sample Measurement										
PARM Code 00011 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	Deg F		Semi-Annually; twice per year	Grab
Temperature (F), Water	Sample Measurement										
PARM Code 00011 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	Deg F		Semi-Annually; twice per year	Grab
Temperature (F), Water	Sample Measurement										
PARM Code 00011 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	Deg F		Semi-Annually; twice per year	Grab
Temperature (F), Water	Sample Measurement										
PARM Code 00011 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	Deg F		Semi-Annually; twice per year	Grab

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (mm/dd/yyyy)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-02A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
pH	Sample Measurement										
PARM Code 00400 P Mon. Site No. OTH-1	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Semi-Annually; twice per year	Grab
pH	Sample Measurement										
PARM Code 00400 Q Mon. Site No. OTH-2	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Semi-Annually; twice per year	Grab
pH	Sample Measurement										
PARM Code 00400 R Mon. Site No. OTH-3	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Semi-Annually; twice per year	Grab
pH	Sample Measurement										
PARM Code 00400 S Mon. Site No. OTH-4	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Semi-Annually; twice per year	Grab
pH	Sample Measurement										
PARM Code 00400 T Mon. Site No. OTH-5	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Semi-Annually; twice per year	Grab
pH	Sample Measurement										
PARM Code 00400 U Mon. Site No. OTH-6	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Semi-Annually; twice per year	Grab
Specific Conductance	Sample Measurement										
PARM Code 00095 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	umhos/cm		Semi-Annually; twice per year	Grab
Specific Conductance	Sample Measurement										
PARM Code 00095 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	umhos/cm		Semi-Annually; twice per year	Grab
Specific Conductance	Sample Measurement										
PARM Code 00095 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	umhos/cm		Semi-Annually; twice per year	Grab
Specific Conductance	Sample Measurement										
PARM Code 00095 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	umhos/cm		Semi-Annually; twice per year	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant | MONITORING GROUP NUMBER: D-02A | PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Specific Conductance	Sample Measurement										
PARM Code 00095 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	umhos/cm		Semi-Annually; twice per year	Grab
Specific Conductance	Sample Measurement										
PARM Code 00095 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	umhos/cm		Semi-Annually; twice per year	Grab
Salinity	Sample Measurement										
PARM Code 00480 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	ppt		Semi-Annually; twice per year	Grab
Salinity	Sample Measurement										
PARM Code 00480 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	ppt		Semi-Annually; twice per year	Grab
Salinity	Sample Measurement										
PARM Code 00480 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	ppt		Semi-Annually; twice per year	Grab
Salinity	Sample Measurement										
PARM Code 00480 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	ppt		Semi-Annually; twice per year	Grab
Salinity	Sample Measurement										
PARM Code 00480 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	ppt		Semi-Annually; twice per year	Grab
Salinity	Sample Measurement										
PARM Code 00480 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	ppt		Semi-Annually; twice per year	Grab
Fluid Density	Sample Measurement										
PARM Code 71820 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	g/ml		Semi-Annually; twice per year	Grab
Fluid Density	Sample Measurement										
PARM Code 71820 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	g/ml		Semi-Annually; twice per year	Grab
Fluid Density	Sample Measurement										
PARM Code 71820 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	g/ml		Semi-Annually; twice per year	Grab
Fluid Density	Sample Measurement										
PARM Code 71820 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	g/ml		Semi-Annually; twice per year	Grab

ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Fluid Density	Sample Measurement										
PARM Code 71820 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	g/ml		Semi-Annually; twice per year	Grab
Fluid Density	Sample Measurement										
PARM Code 71820 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	g/ml		Semi-Annually; twice per year	Grab
Solids, Total Dissolved (TDS)	Sample Measurement										
PARM Code 70295 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Solids, Total Dissolved (TDS)	Sample Measurement										
PARM Code 70295 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-02A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Solids, Total Dissolved (TDS)	Sample Measurement										
PARM Code 70295 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Solids, Total Dissolved (TDS)	Sample Measurement										
PARM Code 70295 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Solids, Total Dissolved (TDS)	Sample Measurement										
PARM Code 70295 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Solids, Total Dissolved (TDS)	Sample Measurement										
PARM Code 70295 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Chloride (as Cl)	Sample Measurement										
PARM Code 00940 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Chloride (as Cl)	Sample Measurement										
PARM Code 00940 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Chloride (as Cl)	Sample Measurement										
PARM Code 00940 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Chloride (as Cl)	Sample Measurement										
PARM Code 00940 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Chloride (as Cl)	Sample Measurement										
PARM Code 00940 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Chloride (as Cl)	Sample Measurement										
PARM Code 00940 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-02A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Sodium, Total Recoverable	Sample Measurement										
PARM Code 00923 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Sodium, Total Recoverable	Sample Measurement										
PARM Code 00923 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Sodium, Total Recoverable	Sample Measurement										
PARM Code 00923 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Sodium, Total Recoverable	Sample Measurement										
PARM Code 00923 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Sodium, Total Recoverable	Sample Measurement										
PARM Code 00923 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Sodium, Total Recoverable	Sample Measurement										
PARM Code 00923 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Calcium, Total Recoverable	Sample Measurement										
PARM Code 00918 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Calcium, Total Recoverable	Sample Measurement										
PARM Code 00918 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Calcium, Total Recoverable	Sample Measurement										
PARM Code 00918 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Calcium, Total Recoverable	Sample Measurement										
PARM Code 00918 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab

ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-02A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________ To: ____________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Calcium, Total Recoverable	Sample Measurement										
PARM Code 00918 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Calcium, Total Recoverable	Sample Measurement										
PARM Code 00918 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Potassium, Total	Sample Measurement										
PARM Code 00937 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Potassium, Total	Sample Measurement										
PARM Code 00937 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Potassium, Total	Sample Measurement										
PARM Code 00937 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Potassium, Total	Sample Measurement										
PARM Code 00937 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Potassium, Total	Sample Measurement										
PARM Code 00937 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Potassium, Total	Sample Measurement										
PARM Code 00937 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Boron, Total Recoverable	Sample Measurement										
PARM Code 00999 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Boron, Total Recoverable	Sample Measurement										
PARM Code 00999 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab

ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-02A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Boron, Total Recoverable	Sample Measurement										
PARM Code 00999 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Boron, Total Recoverable	Sample Measurement										
PARM Code 00999 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Boron, Total Recoverable	Sample Measurement										
PARM Code 00999 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Boron, Total Recoverable	Sample Measurement										
PARM Code 00999 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Copper, Total Recoverable	Sample Measurement										
PARM Code 01119 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Copper, Total Recoverable	Sample Measurement										
PARM Code 01119 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Copper, Total Recoverable	Sample Measurement										
PARM Code 01119 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Copper, Total Recoverable	Sample Measurement										
PARM Code 01119 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Copper, Total Recoverable	Sample Measurement										
PARM Code 01119 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Copper, Total Recoverable	Sample Measurement										
PARM Code 01119 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab

ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-02A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Iron, Total Recoverable	Sample Measurement										
PARM Code 00980 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Iron, Total Recoverable	Sample Measurement										
PARM Code 00980 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Iron, Total Recoverable	Sample Measurement										
PARM Code 00980 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Iron, Total Recoverable	Sample Measurement										
PARM Code 00980 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Iron, Total Recoverable	Sample Measurement										
PARM Code 00980 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Iron, Total Recoverable	Sample Measurement										
PARM Code 00980 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Magnesium, Total Recoverable	Sample Measurement										
PARM Code 00921 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Magnesium, Total Recoverable	Sample Measurement										
PARM Code 00921 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Magnesium, Total Recoverable	Sample Measurement										
PARM Code 00921 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Magnesium, Total Recoverable	Sample Measurement										
PARM Code 00921 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-02A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________ To: ____________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Magnesium, Total Recoverable	Sample Measurement										
PARM Code 00921 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Magnesium, Total Recoverable	Sample Measurement										
PARM Code 00921 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Zinc, Total Recoverable	Sample Measurement										
PARM Code 01094 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Zinc, Total Recoverable	Sample Measurement										
PARM Code 01094 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Zinc, Total Recoverable	Sample Measurement										
PARM Code 01094 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Zinc, Total Recoverable	Sample Measurement										
PARM Code 01094 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Zinc, Total Recoverable	Sample Measurement										
PARM Code 01094 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Zinc, Total Recoverable	Sample Measurement										
PARM Code 01094 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Sulfate, Total	Sample Measurement										
PARM Code 00945 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Sulfate, Total	Sample Measurement										
PARM Code 00945 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-02A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Sulfate, Total	Sample Measurement										
PARM Code 00945 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Sulfate, Total	Sample Measurement										
PARM Code 00945 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Sulfate, Total	Sample Measurement										
PARM Code 00945 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Sulfate, Total	Sample Measurement										
PARM Code 00945 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Ammonia, Total (as N)	Sample Measurement										
PARM Code 00610 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Ammonia, Total (as N)	Sample Measurement										
PARM Code 00610 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Ammonia, Total (as N)	Sample Measurement										
PARM Code 00610 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Ammonia, Total (as N)	Sample Measurement										
PARM Code 00610 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Ammonia, Total (as N)	Sample Measurement										
PARM Code 00610 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Ammonia, Total (as N)	Sample Measurement										
PARM Code 00610 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab

ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-02A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: _______________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrogen, Ammonia, Total (as NH4)	Sample Measurement										
PARM Code 71845 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Ammonia, Total (as NH4)	Sample Measurement										
PARM Code 71845 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Ammonia, Total (as NH4)	Sample Measurement										
PARM Code 71845 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Ammonia, Total (as NH4)	Sample Measurement										
PARM Code 71845 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Ammonia, Total (as NH4)	Sample Measurement										
PARM Code 71845 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Ammonia, Total (as NH4)	Sample Measurement										
PARM Code 71845 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Ammonia, Unionized (as NH3)	Sample Measurement										
PARM Code 00619 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Ammonia, Unionized (as NH3)	Sample Measurement										
PARM Code 00619 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Ammonia, Unionized (as NH3)	Sample Measurement										
PARM Code 00619 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Ammonia, Unionized (as NH3)	Sample Measurement										
PARM Code 00619 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-02A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Ammonia, Unionized (as NH3)	Sample Measurement										
PARM Code 00619 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Ammonia, Unionized (as NH3)	Sample Measurement										
PARM Code 00619 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrite plus Nitrate, Total 1 det. (as N)	Sample Measurement										
PARM Code 00630 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrite plus Nitrate, Total 1 det. (as N)	Sample Measurement										
PARM Code 00630 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrite plus Nitrate, Total 1 det. (as N)	Sample Measurement										
PARM Code 00630 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrite plus Nitrate, Total 1 det. (as N)	Sample Measurement										
PARM Code 00630 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrite plus Nitrate, Total 1 det. (as N)	Sample Measurement										
PARM Code 00630 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrite plus Nitrate, Total 1 det. (as N)	Sample Measurement										
PARM Code 00630 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Kjeldahl, Total (as N)	Sample Measurement										
PARM Code 00625 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Kjeldahl, Total (as N)	Sample Measurement										
PARM Code 00625 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-02A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrogen, Kjeldahl, Total (as N)	Sample Measurement										
PARM Code 00625 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Kjeldahl, Total (as N)	Sample Measurement										
PARM Code 00625 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Kjeldahl, Total (as N)	Sample Measurement										
PARM Code 00625 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Kjeldahl, Total (as N)	Sample Measurement										
PARM Code 00625 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Total	Sample Measurement										
PARM Code 00600 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Total	Sample Measurement										
PARM Code 00600 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Total	Sample Measurement										
PARM Code 00600 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Total	Sample Measurement										
PARM Code 00600 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Total	Sample Measurement										
PARM Code 00600 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Total	Sample Measurement										
PARM Code 00600 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-02A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Phosphorus, Total (as P)	Sample Measurement										
PARM Code 00665 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Phosphorus, Total (as P)	Sample Measurement										
PARM Code 00665 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Phosphorus, Total (as P)	Sample Measurement										
PARM Code 00665 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Phosphorus, Total (as P)	Sample Measurement										
PARM Code 00665 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Phosphorus, Total (as P)	Sample Measurement										
PARM Code 00665 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Phosphorus, Total (as P)	Sample Measurement										
PARM Code 00665 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Phosphate, Ortho (as P)	Sample Measurement										
PARM Code 70507 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Phosphate, Ortho (as P)	Sample Measurement										
PARM Code 70507 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Phosphate, Ortho (as P)	Sample Measurement										
PARM Code 70507 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Phosphate, Ortho (as P)	Sample Measurement										
PARM Code 70507 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-02A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Phosphate, Ortho (as P)	Sample Measurement										
PARM Code 70507 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Phosphate, Ortho (as P)	Sample Measurement										
PARM Code 70507 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab

ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed submit this report to: http://www.fldepportal.com/go/

PERMITTEE NAME: FPL
MAILING ADDRESS: 700 Universe Blvd
Juno Beach, Florida 33408-

FACILITY: FPL Turkey Point Plant
LOCATION: 9700 SW 344th St

Homestead, FL 33035-1800

COUNTY: Miami-Dade
OFFICE: Tallahassee

PERMIT NUMBER: FL0001562-012-IW1N

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: I-001
MONITORING GROUP DESCRIPTION: Once-through non-contact cooling water and other wastewater to the closed cooling canal system.
RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: ____________________ To: ____________________

REPORT FREQUENCY: Monthly
PROGRAM: Industrial

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Temperature (F), Water	Sample Measurement										
PARM Code 00011 P Mon. Site No. OUI-1	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Biochemical Oxygen Demand-5	Sample Measurement										
PARM Code 00310 P Mon. Site No. CAL-1	Permit Requirement						Report (Day.Max.)	mg/L		Monthly	Grab
Oxygen, Dissolved Percent Saturation	Sample Measurement										
PARM Code 00301 P Mon. Site No. CAL-1	Permit Requirement				Report (Min.Mo.Avg.)			percent		Monthly	Calculated
Oxidation-Reduction Potential	Sample Measurement										
PARM Code 00090 P Mon. Site No. CAL-1	Permit Requirement		Report (Day.Max.)	mV						Monthly	Meter
Color	Sample Measurement										
PARM Code 00080 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	PCU		Monthly	Grab
Salinity	Sample Measurement										
PARM Code 00480 P Mon. Site No. CAL-1	Permit Requirement						Report (Day.Max.)	ppt		Monthly	Grab

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (mm/dd/yyyy)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: I-001

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Salinity	Sample Measurement										
PARM Code 00480 R Mon. Site No. CAL-1	Permit Requirement						Report (Mo.Avg.)	ppt		Monthly	Grab
Salinity	Sample Measurement										
PARM Code 00480 Y Mon. Site No. CAL-1	Permit Requirement					Report (An.Avg.)		ppt		Daily; 24 hours	Grab

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed submit this report to: http://www.fldepportal.com/go/

PERMITTEE NAME: FPL
MAILING ADDRESS: 700 Universe Blvd
Juno Beach, Florida 33408-

FACILITY: FPL Turkey Point Plant
LOCATION: 9700 SW 344th St

Homestead, FL 33035-1800

COUNTY: Miami-Dade
OFFICE: Tallahassee

PERMIT NUMBER: FL0001562-012-IW1N

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: I-001
MONITORING GROUP DESCRIPTION: Once-through non-contact cooling water and other wastewater to the closed cooling canal system.

REPORT FREQUENCY: Quarterly
PROGRAM: Industrial

RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: ____________________ To: ____________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Solids, Total Suspended	Sample Measurement										
PARM Code 00530 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
pH	Sample Measurement										
PARM Code 00400 P Mon. Site No. OUI-1	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	Grab
Solids, Total Dissolved (TDS)	Sample Measurement										
PARM Code 70295 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Specific Conductance	Sample Measurement										
PARM Code 00095 P Mon. Site No. CAL-1	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	Grab
Turbidity	Sample Measurement										
PARM Code 00070 P Mon. Site No. CAL-2	Permit Requirement						Report (Day.Max.)	NTU		Quarterly	Grab
Nitrogen, Ammonia, Total (as N)	Sample Measurement										
PARM Code 00610 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (mm/dd/yyyy)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: I-001

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrogen, Ammonia, Total (as N)	Sample Measurement										
PARM Code 00610 Q Mon. Site No. CAL-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Ammonia, Unionized (as NH3)	Sample Measurement										
PARM Code 00619 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Ammonia, Unionized (as NH3)	Sample Measurement										
PARM Code 00619 Q Mon. Site No. CAL-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as NH4)	Sample Measurement										
PARM Code 71845 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as NH4)	Sample Measurement										
PARM Code 71845 Q Mon. Site No. CAL-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N)	Sample Measurement										
PARM Code 00630 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N)	Sample Measurement										
PARM Code 00630 Q Mon. Site No. CAL-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N)	Sample Measurement										
PARM Code 00625 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N)	Sample Measurement										
PARM Code 00625 Q Mon. Site No. CAL-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Total	Sample Measurement										
PARM Code 00600 P Mon. Site No. OUI-1	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: I-001

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrogen, Total	Sample Measurement										
PARM Code 00600 Q Mon. Site No. CAL-1	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Phosphate, Ortho (as PO4)	Sample Measurement										
PARM Code 00660 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4)	Sample Measurement										
PARM Code 00660 Q Mon. Site No. CAL-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P)	Sample Measurement										
PARM Code 00665 P Mon. Site No. OUI-1	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P)	Sample Measurement										
PARM Code 00665 Q Mon. Site No. CAL-1	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Chlorophyll a	Sample Measurement										
PARM Code 32230 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chlorophyll a	Sample Measurement										
PARM Code 32230 Q Mon. Site No. CAL-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl)	Sample Measurement										
PARM Code 00940 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable	Sample Measurement										
PARM Code 00923 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfide, Total	Sample Measurement										
PARM Code 00745 P Mon. Site No. CAL-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed submit this report to: http://www.fldepportal.com/go/

PERMITTEE NAME: FPL
MAILING ADDRESS: 700 Universe Blvd
Juno Beach, Florida 33408-

FACILITY: FPL Turkey Point Plant
LOCATION: 9700 SW 344th St

Homestead, FL 33035-1800

COUNTY: Miami-Dade
OFFICE: Tallahassee

PERMIT NUMBER: FL0001562-012-IW1N

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: I-001
MONITORING GROUP DESCRIPTION: Once-through non-contact cooling water and other wastewater to the closed cooling canal system.

REPORT FREQUENCY: Semi-annually
PROGRAM: Industrial

RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: ____________________ To: ____________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Copper, Total Recoverable	Sample Measurement										
PARM Code 01119 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Copper, Total Recoverable	Sample Measurement										
PARM Code 01119 Q Mon. Site No. CAL-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Iron, Total Recoverable	Sample Measurement										
PARM Code 00980 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Iron, Total Recoverable	Sample Measurement										
PARM Code 00980 Q Mon. Site No. CAL-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Zinc, Total Recoverable	Sample Measurement										
PARM Code 01094 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Zinc, Total Recoverable	Sample Measurement										
PARM Code 01094 Q Mon. Site No. CAL-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (mm/dd/yyyy)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

DEP Form 62-620.910(10), Effective Nov. 29, 1994

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant | MONITORING GROUP NUMBER: I-001 | PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: ____________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Boron, Total Recoverable	Sample Measurement										
PARM Code 00999 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Magnesium, Total Recoverable	Sample Measurement										
PARM Code 00921 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Sulfate, Total	Sample Measurement										
PARM Code 00945 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab

ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

INSTRUCTIONS FOR COMPLETING THE WASTEWATER DISCHARGE MONITORING REPORT

Read these instructions before completing the DMR. Hard copies and/or electronic copies of the required parts of the DMR were provided with the permit. All required information shall be completed in full and typed or printed in ink. A signed, original DMR shall be mailed to the address printed on the DMR by the 28th of the month following the monitoring period. Facilities who submit their DMR(s) electronically through eDMR do not need to submit a hardcopy DMR. The DMR shall not be submitted before the end of the monitoring period.

The DMR consists of three parts--A, B, and D--all of which may or may not be applicable to every facility. Facilities may have one or more Part A's for reporting effluent or reclaimed water data. All domestic wastewater facilities will have a Part B for reporting daily sample results. Part D is used for reporting ground water monitoring well data.

When results are not available, the following codes should be used on parts A and D of the DMR and an explanation provided where appropriate. Note: Codes used on Part B for raw data are different.

CODE	DESCRIPTION/INSTRUCTIONS
ANC	Analysis not conducted.
DRY	Dry Well
FLD	Flood disaster.
IFS	Insufficient flow for sampling.
LS	Lost sample.
MNR	Monitoring not required this period.

CODE	DESCRIPTION/INSTRUCTIONS
NOD	No discharge from/to site.
OPS	Operations were shutdown so no sample could be taken.
OTH	Other. Please enter an explanation of why monitoring data were not available.
SEF	Sampling equipment failure.

When reporting analytical results that fall below a laboratory's reported method detection limits or practical quantification limits, the following instructions should be used, unless indicated otherwise in the permit or on the DMR:

1. Results greater than or equal to the PQL shall be reported as the measured quantity.
2. Results less than the PQL and greater than or equal to the MDL shall be reported as the laboratory's MDL value. These values shall be deemed equal to the MDL when necessary to calculate an average for that parameter and when determining compliance with permit limits.
3. Results less than the MDL shall be reported by entering a less than sign ("<") followed by the laboratory's MDL value, e.g. < 0.001. A value of one-half the MDL or one-half the effluent limit, whichever is lower, shall be used for that sample when necessary to calculate an average for that parameter. Values less than the MDL are considered to demonstrate compliance with an effluent limitation.

PART A -DISCHARGE MONITORING REPORT (DMR)

Part A of the DMR is comprised of one or more sections, each having its own header information. Facility information is preprinted in the header as well as the monitoring group number, whether the limits and monitoring requirements are interim or final, and the required submittal frequency (e.g. monthly, annually, quarterly, etc.). Submit Part A based on the required reporting frequency in the header and the instructions shown in the permit. The following should be completed by the permittee or authorized representative:

Resubmitted DMR: Check this box if this DMR is being re-submitted because there was information missing from or information that needed correction on a previously submitted DMR. The information that is being revised should be clearly noted on the re-submitted DMR (e.g. highlight, circle, etc.)
No Discharge From Site: Check this box if no discharge occurs and, as a result, there are no data or codes to be entered for all of the parameters on the DMR for the entire monitoring group number; however, if the monitoring group includes other monitoring locations (e.g., influent sampling), the "NOD" code should be used to individually denote those parameters for which there was no discharge.
Monitoring Period: Enter the month, day, and year for the first and last day of the monitoring period (i.e. the month, the quarter, the year, etc.) during which the data on this report were collected and analyzed.
Sample Measurement: Before filling in sample measurements in the table, check to see that the data collected correspond to the limit indicated on the DMR (i.e. interim or final) and that the data correspond to the monitoring group number in the header. Enter the data or calculated results for each parameter on this row in the non-shaded area above the limit. Be sure the result being entered corresponds to the appropriate statistical base code (e.g. annual average, monthly average, single sample maximum, etc.) and units. Data qualifier codes are not to be reported on Part A.
No. Ex.: Enter the number of sample measurements during the monitoring period that exceeded the permit limit for each parameter in the non-shaded area. If none, enter zero.
Frequency of Analysis: The shaded areas in this column contain the minimum number of times the measurement is required to be made according to the permit. Enter the actual number of times the measurement was made in the space above the shaded area.
Sample Type: The shaded areas in this column contain the type of sample (e.g. grab, composite, continuous) required by the permit. Enter the actual sample type that was taken in the space above the shaded area.
Signature: This report must be signed in accordance with Rule 62-620.305, F.A.C. Type or print the name and title of the signing official. Include the telephone number where the official may be reached in the event there are questions concerning this report. Enter the date when the report is signed.
Comment and Explanation of Any Violations: Use this area to explain any exceedances, any upset or by-pass events, or other items which require explanation. If more space is needed, reference all attachments in this area.

PART B - DAILY SAMPLE RESULTS

Monitoring Period: Enter the month, day, and year for the first and last day of the monitoring period (i.e. the month, the quarter, the year, etc.) during which the data on this report were collected and analyzed.
Daily Monitoring Results: Transfer all analytical data from your facility's laboratory or a contract laboratory's data sheets for all day(s) that samples were collected. Record the data in the units indicated. Table 1 in Chapter 62-160, F.A.C., contains a complete list of all the data qualifier codes that your laboratory may use when reporting analytical results. However, when transferring numerical results onto Part B of the DMR, only the following data qualifier codes should be used and an explanation provided where appropriate.

CODE	DESCRIPTION/INSTRUCTIONS
<	The compound was analyzed for but not detected.
A	Value reported is the mean (average) of two or more determinations.
J	Estimated value, value not accurate.
Q	Sample held beyond the actual holding time.
Y	Laboratory analysis was from an unpreserved or improperly preserved sample.

To calculate the monthly average, add each reported value to get a total. For flow, divide this total by the number of days in the month. For all other parameters, divide the total by the number of observations.
Plant Staffing: List the name, certificate number, and class of all state certified operators operating the facility during the monitoring period. Use additional sheets as necessary.

PART D - GROUND WATER MONITORING REPORT

Monitoring Period: Enter the month, day, and year for the first and last day of the monitoring period (i.e. the month, the quarter, the year, etc.) during which the data on this report were collected and analyzed.
Date Sample Obtained: Enter the date the sample was taken. Also, check whether or not the well was purged before sampling.
Time Sample Obtained: Enter the time the sample was taken.
Sample Measurement: Record the results of the analysis. If the result was below the minimum detection limit, indicate that. Data qualifier codes are not to be reported on Part D.
Detection Limits: Record the detection limits of the analytical methods used.
Analysis Method: Indicate the analytical method used. Record the method number from Chapter 62-160 or Chapter 62-601, F.A.C., or from other sources.
Sampling Equipment Used: Indicate the procedure used to collect the sample (e.g. airlift, bucket/bailer, centrifugal pump, etc.)
Samples Filtered: Indicate whether the sample obtained was filtered by laboratory (L), filtered in field (F), or unfiltered (N).
Signature: This report must be signed in accordance with Rule 62-620.305, F.A.C. Type or print the name and title of the signing official. Include the telephone number where the official may be reached in the event there are questions concerning this report. Enter the date when the report is signed.
Comments and Explanation: Use this space to make any comments on or explanations of results that are unexpected. If more space is needed, reference all attachments in this area.

SPECIAL INSTRUCTIONS FOR LIMITED WET WEATHER DISCHARGES

Flow (Limited Wet Weather Discharge): Enter the measured average flow rate during the period of discharge or divide gallons discharged by duration of discharge (converted into days). Record in million gallons per day (MGD).
Flow (Upstream): Enter the average flow rate in the receiving stream upstream from the point of discharge for the period of discharge. The average flow rate can be calculated based on two measurements; one made at the start and one made at the end of the discharge period. Measurements are to be made at the upstream gauging station described in the permit.
Actual Stream Dilution Ratio: To calculate the Actual Stream Dilution Ratio, divide the average upstream flow rate by the average discharge flow rate. Enter the Actual Stream Dilution Ratio accurate to the nearest 0.1.
No. of Days the SDF > Stream Dilution Ratio: For each day of discharge, compare the minimum Stream Dilution Factor (SDF) from the permit to the calculated Stream Dilution Ratio. On Part B of the DMR, enter an asterisk (*) if the SDF is greater than the Stream Dilution Ratio on any day of discharge. On Part A of the DMR, add up the days with an "*" and record the total number of days the Stream Dilution Factor was greater than the Stream Dilution Ratio.
$CBOD_5$: Enter the average $CBOD_5$ of the reclaimed water discharged during the period shown in duration of discharge.
TKN: Enter the average TKN of the reclaimed water discharged during the period shown in duration of discharge.
Actual Rainfall: Enter the actual rainfall for each day on Part B. Enter the actual cumulative rainfall to date for this calendar year and the actual total monthly rainfall on Part A. The cumulative rainfall to date for this calendar year is the total amount of rain, in inches, that has been recorded since January 1 of the current year through the month for which this DMR contains data.
Rainfall During Average Rainfall Year: On Part A, enter the total monthly rainfall during the average rainfall year and the cumulative rainfall for the average rainfall year. The cumulative rainfall for the average rainfall year is the amount of rain, in inches, which fell during the average rainfall year from January through the month for which this DMR contains data.
No. of Days LWWD Activated During Calendar Year: Enter the cumulative number of days that the limited wet weather discharge was activated since January 1 of the current year.
Reason for Discharge: Attach to the DMR a brief explanation of the factors contributing to the need to activate the limited wet weather discharge.

BEFORE THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION,

Petitioner,

v.

FLORIDA POWER & LIGHT COMPANY, INC.,

Respondent.
_______________________________/

IN THE OFFICE OF THE SOUTHEAST DISTRICT

OGC File No.: 16-0241

NOTICE OF VIOLATION AND ORDERS FOR CORRECTIVE ACTION

To: Florida Power & Light Company, Inc.
c/o J. E. Leon, Registered Agent
4200 West Flagler Street
Suite 2113
Miami, Florida 33134

Certified Return Receipt No. 7013 2630 0001 2651 6074

Pursuant to the authority of section 403.121(2), Florida Statutes, the State of Florida Department of Environmental Protection (Department) gives notice to Florida Power & Light Company, Inc. (Respondent) of the following findings of fact and conclusions of law with respect to violations of chapter 403, Florida Statutes.

FINDINGS OF FACT

1. The Department is the administrative agency of the State of Florida having the power and duty to protect Florida's air and water resources and to

administer and enforce the provisions of chapter 403, Florida Statutes, and the rules promulgated thereunder in title 62, Florida Administrative Code.

2. Respondent is an active Florida corporation, registered to conduct business in the State of Florida. Respondent is a regulated Florida Utility providing electric service to 4.7 million customers in 35 counties.

3. Respondent owns and operates the Turkey Point Power Plant located on approximately 9,400 acres in unincorporated Miami-Dade County, Florida along the coastline adjacent to Biscayne Bay (Turkey Point), with a permitted address of 9670 S.W. 344 Street, Florida City, Miami-Dade County, Florida.

4. Turkey Point consists of five electrical generating units and also includes a cooling canal system (CCS). The CCS is made up of a 5,900-acre network of canals providing a heat removal function for the five electrical generating units.

5. Respondent is the permittee of National Pollutant Discharge Elimination System Industrial Wastewater Permit Number FL0001562 (Permit). Respondent operates the CCS under the Permit.

6. The CCS canals are unlined and have a direct connection to the groundwater.

7. On or about December 23, 2014, the Department issued an Administrative Order related to the CCS at Turkey Point.

8. On or about February 9, 2015, the Administrative Order was petitioned and subsequently referred to the Division of Administrative Hearings (DOAH) (Consolidated Case Numbers 15-1746 and 15-1747).

9. On February 15, 2016, the Administrative Law Judge issued a Recommended Order in DOAH Case Numbers 15-1746 and 15-1747 (Recommended Order).

10. On April 21, 2016, the Recommended Order, as modified in part, was adopted by the Department in Final Order Number 16-0111.

11. The following findings in the Final Order are hereby incorporated in this Notice of Violation:

a. The CCS is the major contributing cause to the continuing westward movement of the saline water interface;

b. The CCS groundwater discharge of hypersaline water contributes to saltwater intrusion;

c. Rule 62-520.400, Florida Administrative Code, prohibits a discharge in concentrations that impair the reasonable and beneficial use of adjacent waters;

d. Saltwater intrusion into the area west of the CCS is impairing the reasonable and beneficial use of adjacent G-II groundwater and therefore, is a violation of the minimum criteria for groundwater in rule 62-520.400, Florida Administrative Code.

12. Condition IV. 1. of the Permit requires that Respondent's discharge to groundwater shall not cause a violation of the minimum criteria for groundwater as specified in rules 62-520.400 and 62-520.430, Florida Administrative Code.

13. Section 403.161(1)(b), Florida Statutes, states, in part, it is a violation to fail

to comply with a permit issued by the Department.

CONCLUSIONS OF LAW

14. The Department has evaluated the Findings of Fact with regard to the requirements of chapter 403, Florida Statutes, and title 62, Florida Administrative Code. Based on the foregoing facts, the Department has made the following conclusions of law.

15. Respondent is a "person" as defined in section 403.031(5), Florida Statutes.

16. Respondent is the permittee of the Permit.

17. Respondent operates the CCS under the Permit.

18. The facts set forth above constitute a violation of section 403.161(1)(b), Florida Statutes, for failing to comply with Condition IV. 1. of the Permit.

ORDERS FOR CORRECTIVE ACTION

19. The Department has alleged that the activities related in the Findings of Fact constitute violations of Florida law. The Orders for Corrective Action state what you, Respondent, must do in order to correct and redress the violations alleged in this Notice. The Department will adopt the Orders for Corrective Action as part of its Final Order in this case unless Respondent either files a timely petition for a formal hearing or informal proceeding, pursuant to section 403.121(2)(c), Florida Statutes, or files written notice with the Department opting out of this administrative process, pursuant to section 403.121(2)(c), Florida Statutes. (See Notice of Rights.) If Respondent fails to comply with the corrective actions ordered by the Final Order, the Department is authorized to file suit seeking judicial enforcement of the Department's Order pursuant

to sections 120.69, 403.121, and 403.131, Florida Statutes.

20. Pursuant to the authority of sections 403.061(8) and 403.121, Florida Statutes, the Department proposes to adopt in its Final Order in this case the following specific corrective actions that will redress the alleged violations.

21. Within 21 days of the effective date of this Order, Respondent shall enter into consultations with the Department to address abatement and remediation measures necessary to address the violation set forth above. At the start of this consultation, Respondent shall provide the following information/data to the Department:

a. All final studies and analyses of the effects of the CCS on ground waters.

b. All final studies and analyses regarding abatement, remediation, modeling and/or prevention of the hypersaline plume, to which the CCS contributes.

22. Respondent and Department shall attempt to enter into an agreeable consent order or equivalent that incorporates corrective actions to abate and remediate the effects of the violation listed above. The consent order or equivalent shall, at a minimum, delineate actions to abate the CCS contribution to the hypersaline plume, reduce the size of the hypersaline plume, and prevent future harm to waters of the State.

23. If parties are unable to enter into a consent order or equivalent incorporating the terms described above, within 60 days of the effective date of this

Order, the Department may issue a comprehensive management plan to, at a minimum, abate the CCS contribution to the hypersaline plume, reduce the size of the hypersaline plume, and prevent future harm to waters of the State. Respondent shall implement the comprehensive management plan as issued by the Department.

24. Except as otherwise provided, all submittals required by this Order shall be sent to Elsa Potts, Program Administrator Water Resource Management, Department of Environmental Protection, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

NOTICE OF RIGHTS

25. Respondent's rights to negotiate, litigate or transfer this action are set forth below.

Right to Negotiate

26. This matter may be resolved if the Department and Respondent enter into a consent order, in accordance with section 120.57(4), Florida Statutes, upon such terms and conditions as may be mutually agreeable.

Right to Request a Hearing

27. Respondent has the right to a formal administrative hearing pursuant to sections 120.569, 120.57(1), and 403.121(2), Florida Statutes, if Respondent disputes issues of material fact raised by this Notice of Violation and Orders for Corrective Action (Notice). At a formal hearing, Respondent will have the opportunity to be represented by counsel or other qualified representative, to present evidence and argument on all issues involved, to conduct cross-examination and submit rebuttal evidence, to submit proposed findings of fact and orders, and to file exceptions to any

order or administrative law judge's recommended order.

28. Respondent has the right to an informal administrative proceeding pursuant to sections 120.569 and 120.57(2), Florida Statutes, if Respondent does not dispute issues of material fact raised by this Notice. If an informal proceeding is held, Respondent will have the opportunity to be represented by counsel or other qualified representative, to present to the agency written or oral evidence in opposition to the Department's proposed action, or to present a written statement challenging the grounds upon which the Department is justifying its proposed action.

29. If Respondent desires a formal hearing or an informal proceeding, Respondent must file a written responsive pleading entitled "Petition for Administrative Proceeding" within 20 days of receipt of this Notice. The petition must be in the form required by rule 28-106.2015, Florida Administrative Code.

(a) The Department's Notice identification number and the county in which the subject matter or activity is located;

(b) The name, address, and telephone number, and facsimile number (if any) of each respondent;

(c) The name, address, telephone number, and facsimile number of the attorney or qualified representative of respondent, if any, upon whom service of pleadings and other papers shall be made;

(d) A statement of when respondent received the Notice; and

(e) A statement requesting an administrative hearing identifying those material facts that are in dispute. If there are none, the petition must so indicate.

A petition is filed when it is received by the Department's Office of General Counsel, 3900 Commonwealth Boulevard, MS-35, Tallahassee, Florida, 32399-3000.

Right to Request Mediation

30. Respondent may request mediation after filing a petition for hearing. Requesting mediation will not adversely affect the right to a hearing if mediation does not result in a settlement. The mediation will be held if the parties enter a written agreement, which is described below, within 30 days after receipt of the Notice. The mediation must be completed within 60 days of the agreement unless the parties otherwise agree.

The agreement to mediate must include the following:

(a) The names, addresses, and telephone numbers of any persons who may attend the mediation;

(b) The name, address, and telephone number of the mediator selected by the parties, or a provision for selecting a mediator within a specified time;

(c) The agreed allocation of the costs and fees associated with the mediation;

(d) The agreement of the parties on the confidentiality of discussions and documents introduced during mediation;

(e) The date, time, and place of the first mediation session, or a deadline for holding the first session, if no mediator has yet been chosen;

(f) The name of each party's representative who shall have authority to settle or recommend settlement; and

(g) The signatures of all parties or their authorized representatives.

As provided in section 120.573 of the Florida Statutes, the timely agreement of all parties to mediate will toll the time limitations imposed by sections 120.569 and 120.57 for requesting and holding an administrative hearing. Unless otherwise agreed by the parties, the mediation must be concluded within sixty days of the execution of the agreement. If mediation results in settlement of the administrative dispute, the Department must enter a final order incorporating the agreement of the parties. Persons whose substantial interests will be affected by such a modified final decision of the Department have a right to petition for a hearing only in accordance with the requirements for such petitions set forth above, and must therefore file their petitions within 21 days of receipt of this notice. If mediation terminates without settlement of the dispute, the Department shall notify the Respondent in writing that the administrative hearing processes under sections 120.569 and 120.57 remain available for disposition of the dispute, and the notice will specify the deadlines that then will apply for challenging the agency action and electing remedies under those two statutes.

Waivers

31. Respondent will waive the right to a formal hearing or an informal proceeding if a petition is not filed with the Department within 20 days of receipt of this Notice. These time limits may be varied only by written consent of the Department.

General Provisions

32. The allegations of this Notice together with the Orders for Corrective Action will be adopted by the Department in a Final Order if Respondent fails to timely file a petition for a formal hearing or informal proceeding, pursuant to section 403.121, Florida Statutes. A Final Order will constitute a full and final adjudication of the matters alleged in this Notice.

33. If Respondent fails to comply with the Final Order, the Department is authorized to file suit in circuit court seeking a mandatory injunction to compel compliance with the Order, pursuant to sections 120.69, 403.121 and 403.131, Florida Statutes. The Department may also seek to recover damages, all costs of litigation including reasonable attorney's fees and expert witness fees, and civil penalties of not more than $10,000 day for each day that Respondent has failed to comply with the Final Order.

34. The Department is not barred by the issuance of this Notice from maintaining an independent action in circuit court with respect to the alleged violations. If such action is warranted, the Department may seek injunctive relief, damages, civil penalties of not more than $10,000 per day, and all costs of litigation.

35. Copies of Department rules referenced in this Notice may be examined at any Department Office or may be obtained by written request to the person listed on the last page of this Notice.

DATED this 25th day of April, 2016.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Frederick L. Aschauer, Jr., Director
Division of Water Resource Management

Copies furnished to:
Larry Morgan, OGC Enforcement Section
Mail Station 35

PLACE STICKER AT TOP OF ENVELOPE TO THE RIGHT OF THE RETURN ADDRESS, FOLD AT DOTTED LINE

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OFFICIAL USE

Postage	$	Postmark Here
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Return Receipt Fee (Endorsement Required)		
Restricted Delivery Fee (Endorsement Required)		
Total Postage & Fees	$	

Sent To
Street, Apt. No.; or PO Box No.
City, State, ZIP+4

Florida Power & Light Company, Inc.
c/o J.E. Leon, Registered Agent
4200 West Flagler Street, Suite 2113
Miami, FL 33134

PS Form 3800, August 2006 — See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Florida Power & Light Company, Inc.
c/o J.E. Leon, Registered Agent
4200 West Flagler Street, Suite 2113
Miami, FL 33134

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X
☐ Agent
☐ Addressee

B. Received by (*Printed Name*)

C. Date of Delivery

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☑ Certified Mail ☐ Express Mail
☐ Registered ☑ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Transfer from service label)* 7013 2630 0001 2651 6074

PS Form 3811, February 2004 — Domestic Return Receipt 4/25/16 Ltr.-FPL NOV 102595-02-M-1540

EXECUTION VERSION

AGREEMENT FOR RECLAIMED WATER PROCESSING, TREATMENT AND USE AT THE FLORIDA POWER & LIGHT TURKEY POINT COMPLEX

THIS AGREEMENT FOR RECLAIMED WATER PROCESSING, TREATMENT AND USE (this "**Agreement**"), is made and entered into this June [ ], 2020, by and between Miami-Dade County, a political subdivision of the State of Florida, (the "**County**"), and Florida Power & Light Company, a Florida corporation ("**FPL**"), and together with the County, the "**Parties**").

WITNESSETH:

WHEREAS, the Miami-Dade Water and Sewer Department (the "**Department**") operates and maintains the County's wastewater treatment and reclamation system; and

WHEREAS, the County currently provides wastewater treatment within Miami-Dade County through three treatment facilities owned and operated by the County (the "**County Wastewater Facilities**"); and

WHEREAS, FPL owns power generation facilities located in southeastern Miami-Dade County, Florida (the "**Turkey Point Complex**" or "**TP Complex**"); and

WHEREAS, the Florida Department of Environmental Protection ("**FDEP**") requires the County to process and treat wastewater in part to produce water technically and economically feasible for reuse ("**Reclaimed Water**") pursuant to Section 403.064, F.S.; and

WHEREAS, FPL is encouraged to utilize Reclaimed Water at the TP Complex should it become available in the necessary quality and quantity; and

WHEREAS, on April 10, 2018, the Miami-Dade County Board of County Commissioners ("Board") approved Resolution No. R-292-18 ("**Resolution**"); and

WHEREAS, the Resolution authorizes the County Mayor or his designee to execute a Joint Participation Agreement with FPL for development of an Advanced Reclaimed Water Project ("Project") and to further negotiate a Reclaimed Water Service Agreement ("**RWSA**") to implement such Project subject to approval by the Board; and

WHEREAS, the project design discussed at the time of the Resolution has been modified to exclude discharge of Reclaimed Water to the Turkey Point cooling canals, or surface waters of surrounding wetlands and Biscayne Bay as a component of this project, and

WHEREAS, the Parties recognize and acknowledge that the County's primary goals in entering this Agreement are the beneficial use of County reclaimed water at the Turkey Point Complex to replace the existing use of Floridan water in cooling towers in a manner which will also protect water resources in the surrounding environment, and

EXECUTION VERSION

WHEREAS, the Advanced Reclaimed Water Project will serve to provide an alternative source of cooling water for Turkey Point Unit 5 Forced Draft Cooling Towers, thereby allowing FPL to seek authorization to redirect Floridan Aquifer water otherwise allocated for this purpose for use in managing salinity levels in the cooling canal system; and

WHEREAS, the Parties have negotiated this Agreement as the RWSA; and

WHEREAS, FPL has identified an opportunity to utilize up to 15,000,000 gallons of Process Water per day at the TP Complex that will help the County satisfy the reuse objectives set forth in Section 403.064, Florida Statutes; and

WHEREAS, FPL desires to construct an advanced reclaimed water treatment facility and associated pipelines and wells necessary to process and further treat up to 15 million gallons per day ("MGD") of Reclaimed Water for use at the TP Complex (the "**FPL Facilities**"); and

WHEREAS, the 15 MGD of Process Water for cooling purposes at TP Unit 5 is consistent with the objectives of the October 7, 2015 Consent Agreement between the County and FPL; and

WHEREAS, the County is prepared to deliver up to 15 MGD of Reclaimed Water from the County Wastewater Facilities to the FPL Facilities; and

WHEREAS, FPL will be responsible for all costs of constructing the FPL Facilities estimated to be $300 million; and

WHEREAS, the County will provide $6.5 million annually to FPL to support operations of the Project;

NOW, THEREFORE, in consideration of the mutual covenants and obligations set forth herein, the County and FPL hereby agree as follows.

ARTICLE I.
DEFINITIONS; INTERPRETATION

1.01 Defined Terms. For the purposes of this Agreement, the following terms shall have the following meanings:

"Additional Facilities" shall have the meaning set forth in Section 6.04(b)(i).

"Advanced Reclaimed Water Project" ("ARWP" or "Project") shall mean the siting, permitting, construction, commissioning, operation and maintenance of the Advanced Wastewater Treatment Facility, the FPL Facilities and the County Facilities for transporting, delivering, and processing Reclaimed Water from the County Facilities into Processed Water for use by FPL at the TP Complex for the Unit 5 existing Forced Draft Cooling Towers.

"Advanced Reclaimed Treatment Facility" means the advanced reclaimed treatment facility that would process Reclaimed Water into Processed Water.

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"Agreement" shall have the meaning set forth in the preamble hereto, and includes all exhibits, schedules and appendices attached hereto.

"Board" shall mean the Miami-Dade County Board of County Commissioners.

"Business Day" means any day on which the Federal Reserve Member Banks in Miami, Florida are open for business.

"County" shall have the meaning set forth in the preamble hereto.

"County Event of Default" shall have the meaning set forth in Section 9.01.

"County Facilities" shall mean facilities necessary for the delivery of up to 15 MGD of Reclaimed Water to the Delivery Point at the SDWWTP as shown on Figure B-1.

"Delivery Point" shall mean the location near the SDWWTP and at the point designated on Figure B-1 where the County will deliver Reclaimed Water to FPL.

"Department" shall have the meaning set forth in the recitals hereto.

"Dispute" shall have the meaning set forth in Section 11.01.

"Effective Date" shall mean the sooner of (1) the date of the expiration of the County Mayor's veto period subsequent to the approval of this Agreement by the Board without the County Mayor vetoing the Board's resolution approving same or (2) the date on which the County Mayor approves the Board-approved resolution authorizing the execution of this Agreement.

"Event of Default" shall mean a County Event of Default or an FPL Event of Default as the context requires.

"Extension Term" shall have the meaning set forth in Section 2.02.

"Force Majeure" shall have the meaning set forth in Section 10.01.

"FPL" shall have the meaning set forth in the preamble hereto.

"FPL Event of Default" shall have the meaning set forth in Section 9.02.

"FPL Facilities" shall mean (i) facilities necessary for the transportation of up to 15 MGD of Reclaimed Water from the County Wastewater Facilities to the FPL treatment facilities at Turkey Point, (ii) the FPL water treatment facility and associated pipelines and equipment to facilitate use of Reclaimed Water, (iii) deep injection well facilities to dispose of Process Wastewater

"Initial Term" shall have the meaning set forth in Section 2.02.

"Incremental Facilities" shall mean any additional pipeline requested by the County for conveyance of future Reclaimed Water volumes in excess of FPL needs up to 60 mgd.

"MGD" shall mean million gallons per day.

EXECUTION VERSION

"Maximum Daily Quantity" shall have the meaning set forth in Exhibit C.

"Meter" shall have the meaning set forth in Section 7.05(a).

"Minimum Daily Quantity" shall have the meaning set forth in Exhibit C.

"O&M" means Operations and Maintenance.

"Operating Agreement" shall have the meaning set forth in Section 5.03.

"Parties" has the meaning specified in the preamble to this Agreement.

"Pipelines" means the pipelines that transport Reclaimed Water from the Delivery Point(s) to the Advanced Reclaimed Treatment Facility at the TP Complex and associated pipelines required for operation of the project.

"Process Wastewater" shall mean non-hazardous waste residuals produced by the FPL Facilities, including blowdown from the Unit 5 cooling towers.

"Process Water" shall mean Reclaimed Water that has been further processed by the FPL Facilities.

"Quality Standard" shall mean those standards for Reclaimed Water that are set forth on Exhibit A to be met at the Delivery Point

"Reclaimed Water" means treated wastewater delivered by the County at the Delivery Point that satisfies the Reclaimed Water Quality Requirements.

"Sentinel Limit" shall mean the water quality limits as defined in Exhibit A, Table A-2.

"Service Initiation Date" means that date on which the County first delivers Reclaimed Water to the Delivery Point for processing and treatment by FPL.

"SDWWTP" shall mean the Water & Sewer Department's South District Waste Water Treatment Plant located in south Miami-Dade County approximately 10 miles north of Turkey Point.

"Target Value" shall mean the water quality limits as defined in Exhibit A, Table A-1.

"Term" shall have the meaning set forth in Section 2.02.

"True Accuracy" shall have the meaning set forth in Section 7.05(a).

"Turkey Point Complex" or "TP Complex" means FPL's power generation site located in southeastern Miami-Dade County.

"Upper Limit" shall mean a upper water quality limit for each of the parameters set forth in Exhibit A, Table A-1.

EXECUTION VERSION

1.02 Interpretation. Unless otherwise expressly provided, for purposes of this Agreement, the following rules of interpretation apply.

(a) Appendices, Exhibits and Schedules. Unless otherwise expressly indicated, any reference in this Agreement to an "Exhibit" or "Schedule" refers to an Exhibit or Schedule to this Agreement. The Appendices, Exhibits and Schedules to this Agreement are hereby incorporated and made a part hereof as if set forth in full herein and are an integral part of this Agreement. Any capitalized terms used in any Appendix, Exhibit or Schedule but not otherwise defined therein are defined as set forth in this Agreement. In the event of conflict or inconsistency, this Agreement shall prevail over any Appendix, Exhibit or Schedule.

(b) Certain Terms. The words such as "herein," "hereinafter," "hereof," and "hereunder" refer to this Agreement (including the Appendices, Exhibits and Schedules to this Agreement) as a whole and not merely to a subdivision in which such words appear unless the context otherwise requires. The word "including" or any variation thereof means "including, without limitation" and does not limit any general statement that it follows to the specific or similar items or matters immediately following it. The words "to the extent" when used in reference to a liability or other matter, means that the liability or other matter referred to is included in part or excluded in part, with the portion included or excluded determined based on the portion of such liability or other matter exclusively related to the subject or period. The word "or" shall be disjunctive but not exclusive. A reference to any Party or to any party to any other agreement or document shall include such party's successors and permitted assigns. Unless stated herein, a reference to any legislation or to any provision of any legislation shall include any amendment to, and any modification or reenactment thereof, any legislative provision substituted therefor and all regulations and statutory instruments issued thereunder or pursuant thereto (provided, that for purposes of any representations and warranties contained in this Agreement that are made as of a specific date, references to any statute shall be deemed to refer to such statute and any rules or regulations promulgated thereunder as amended through such specific date). References "written" or "in writing" include in electronic form. Any reference to "days" shall mean calendar days unless Business Days are expressly specified.

(c) Headings. The division of this Agreement into Articles, Sections, and other subdivisions, and the insertion of headings are for convenience of reference only and do not affect, and will not be utilized in construing or interpreting, this Agreement. All references in this Agreement to any "Section" are to the corresponding Section of this Agreement unless otherwise specified.

ARTICLE II.
CONDITIONS PRECEDENT; TERM

2.01 Conditions Precedent. Notwithstanding the execution and delivery of this Agreement by the Parties, the obligations of the Parties contained herein shall only become effective upon the completion or waiver of those activities set forth in Exhibit D.

2.02 Term. The initial term of this Agreement ("**Initial Term**") shall commence upon the Effective Date and shall, unless this Agreement is either (1) earlier terminated or (2) extended, in either case in accordance with this Agreement, continue through December 31, 2053.

EXECUTION VERSION

This Agreement and each subsequent Extension Term (as defined below) shall automatically renew for a period of five (5) additional years (each such five-year period, an "**Extension Term**"), unless either Party provides written notice to the other of its intention to not have this Agreement renew, not less than one (1) year prior to the end of the Initial Term or Extension Term, as applicable.

2.03 Purchase Right. If FPL has provided notice to the County of its intention not to renew this Agreement, then the County shall have the right to purchase FPL Facilities including access rights to said facilites, at the higher of the book value or the then fair market value as determined by an independent, third-party appraiser agreed to by the Parties and on terms to be negotiated by the Parties acting in good faith. If the County desires to exercise its right to purchase the FPL Facilities, it must notify FPL no later than six (6) months prior to the end of the Initial Term or Extension Term, as applicable.

ARTICLE III.
OBLIGATIONS OF FPL

3.01 Ownership and Operation. FPL shall design, permit, finance, construct, own, operate and maintain in good working order, consistent with industry practice, the FPL Facilities from and on the FPL side of the Delivery Point shown on Figure B-1, such that the Advanced Reclaimed Water Project meets the delivery requirements identified in Exhibit C.

3.02 Responsibilities for County and FPL Facilities.

(a) FPL shall finance, design and construct the County Facilities located on County property if necessary and subject to the County's approval, to transfer the reclaimed water from the property line at the SDWWTP (the County Facilities) shown on Figure B-1 or such other location approved by the County to the TP Complex. For any work done by FPL on County property pursuant to this Agreement, FPL shall provide certificates of insurance as required by the County andshall include the County as an additional insured on all requisite insurance policies. County will own, operate and maintain the County Facilities and be responsible for the costs associated with such responsiblities.

(b) FPL will design and construct the Incremental Facilities requested by the County to provide future pipeline capacity for reclaimed water to the Turkey Point site. If the County requests FPL to construct Incremental Facilities, such Incremental Facilities will be delivered to the County for the County to own, operate and maintain and FPL shall provide the County with access to the Incremental Facilities for operational and maintenance purposes . Subject to the County's review and approval of costs, County will reimburse FPL for all reasonable costs to design, finance, and construct the Incremental Facilites. County will own, operate and maintain the Incremental Facilities and be responsible for the costs associated with such responsiblities.

3.03 Acceptance of Reclaimed Water. Except as otherwise provided herein, FPL shall accept at the Delivery Point (as described in Exhibit B) up to fifteen-million gallons of Reclaimed Water per day (15,000,000 gpd) from the County (the "Maximum Daily Quantity") delivered in accordance with the delivery requirements set forth on Exhibit C.

3.04 Delivery and Processing of Reclaimed Water. FPL shall notify the County in writing of the volume of Reclaimed Water it requires each day. The County shall control the rate of delivery of Reclaimed Water. FPL shall process and treat, or shall cause to be processed and treated, Reclaimed Water that it has requested up to the Maximum Daily Quantity in accordance with this Agreement, in order to produce Process Water.

3.05 Use of Process Water. FPL shall utilize the Processed Water in the forced draft cooling towers for Turkey Point Unit 5. FPL shall not use Process Water for any other purpose without prior approval from applicable federal, state, and local regulatory agencies. If FPL plans to seek additional legal use(s) for reclaimed water at the TP Complex, FPL will advise the County as to the proposed use(s) and seek County input. Furthermore, FPL shall not discharge or dispose of Process Water or Process Wastewater into the Cooling Canal System.

3.06 Disposal of Process Wastewater. FPL is responsible for disposal of the Process Wastewater. FPL shall dispose of the Process Wastewater in compliance with all conditions of the applicable permits, authorizations and approvals.

3.07 Provision of Alternative Sources. FPL shall maintain an alternative source of cooling water for Turkey Point Unit 5 sufficient to provide FPL's needs, in the event of system failures, forced outages, maintenance or Force Majeure events at any portion of the ARWP or a failure of the County to provide Reclaimed Water in accordance with this Agreement.

3.08 Plant Management. FPL shall assign a qualified personnel to act as FPL ARWP Manager and discharge the duties described in Article V.

3.09 FPL Cooperation. FPL shall cooperate with the County in providing available data and information relating to the Project that is requested by the Department of Regulatory and Economic Resources, Division of Environmental Resources Managment for the preparation of reports to the Board.

ARTICLE IV.
OBLIGATIONS OF THE COUNTY

4.01 Delivery of Reclaimed Water. The County shall, at its sole cost and expense, deliver to FPL, at the Delivery Point the required volumes of Reclaimed Water as specified by the FPL ARWP Manager pursuant to Section 3.04, all of which shall meet the Quality Standards as contained in Exhibit A.

4.02 County Facilities. The County shall facilitate, seek to obtain permits, accept, own, operate and maintain the facilities located on County property necessary to transfer Reclaimed Water as required for the ARWP and, in general, cooperate with the development, permitting and construction of the ARWP. Coordination with existing and ongoing renovations at the SDWWTP site will be provided to safely and cost-effectively incorporate the ARWP.

4.03 Provision of Alternative Disposal Method. The County shall, at its sole cost and expense, develop or maintain an alternative method of disposal of the Reclaimed Water in the event of system failures, forced outages, facility maintenance or Force Majeure events at the Project or a failure of FPL to accept, process and treat Reclaimed Water in accordance with this Agreement.

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4.04 Payment for Processing and Treatment. The County shall timely make all payments required pursuant to Article VIII.

4.05 Participation in Plant Operational Review. The County may assign qualified personnel to participate in the review of periodic reports provided by the FPL ARWP Manager.

ARTICLE V.
OPERATIONAL MANAGEMENT

5.01 Authority. FPL will appoint an ARWP Manager who will be responsible for the routine supervision and direction of ARWP operations, maintenance, regulatory compliance, financial management and reporting as described herein. The ARWP Manager will be the point of contact for all communications and inquiries related to the functioning of the ARWP and coordination of operations with the County's SDWWTP. The County shall pay FPL an annual amount of $6.5 million to support the ARWP and FPL shall be responsible for all ARWP operations, maintenance, regulatory compliance, financial management and reporting, excluding those costs identified in Section 4.01.

5.02 Standard of Care. All actions taken by the FPL ARWP Manager shall be consistent with: (i) FPL and County Required Approvals, (ii) all applicable laws, rules and regulations, including, with respect to the maintenance, repair and replacement of the FPL Facilities, Section 606 of County Ordinance No. 93-134, (iii) good industry practices, and (iv) the health and safety of the public, County and FPL employees, contractors, or agents.

5.03 Operating Agreement. Following completion of final design and permitting for the FPL and County Facilities, the Parties will coordinate to develop an Operating Agreement that will describe the operating protocols, sequences, systems, limits, notifications, communications and reporting requirements necessary for safe and efficient operations of the ARWP. Such Operating Agreement will be reviewed and updated annually and utilized by the Parties to train and direct staff and shall govern day-to-day operations of the ARWP.

5.04 Review. If the Agreement is not meeting the County's goals of beneficial use of County reclaimed water at the Turkey Point Complex to replace the use of Floridan water in the existing cooling towers in a manner which will also protect water resources in the surrounding environment within one year of the Service Initiation Date, the County shall notify FPL in order for the Parties to revisit the terms of the Agreement.

ARTICLE VI.
QUALITY STANDARDS

6.01 Reclaimed Water Supply. The County shall ensure that all Reclaimed Water delivered to the Project meets the Reclaimed Water Quality Standards, as set forth in Exhibit A.

6.02 Testing. Testing of the Reclaimed Water shall be conducted in accordance with Section 7.04 and Exhibit A (as applicable).

6.03 Right of Rejection - FPL. If at any time any of the parameters of the Reclaimed Water exceeds any of the Target Values of the Reclaimed Water Quality Standards specified in Exhibit A, Table A-1 or the Sentinel Limits of Table A-2, and such exceedance is confirmed by resampling and analysis by the County, FPL may stop receipt of all or any portion of the Reclaimed Water. Following such failure to meet the Quality Standards or Sentinel Limits, FPL shall be under no obligation to re-commence accepting Reclaimed Water until such time as it is satisfied, through additional testing, that the Reclaimed Water does not exceed the Target Values or Sentinel Limits.

6.04 Exceedances of Reclaimed Water Quality Standards (Table A-1).

(a) If there is an exceedance of the Upper Limits of any of the Reclaimed Water Quality Standards specified in Exhibit A, Table A-1, more than three (3) times in any rolling six (6) month period that is confirmed by the County through its own resampling and analysis, FPL will notify the County and the County shall, within twenty (20) days of its receipt of such notice, develop and deliver to FPL a recovery plan setting out the steps the County will undertake to rectify the repeated exceedances.

(b) If there are no exceedances of the Upper Limits of the Reclaimed Water Quality Standards specified in Exhibit A, Table A-1, over a period of three (3) months following execution of the activities indicated in the County's recovery plan, the count of exceedances will reset to zero. If, however, exceedances persist, FPL, in its sole discretion, shall either (i) require the County to repeat the actions set forth in its recovery plan, (ii) require the County to provide a revised recovery plan, or (iii) independently develop or engage (in consultation with the County and, if the County concurs, at the County's expense) a third party consultant to develop a recovery plan which the County shall execute.

(i) The recovery plan(s) may include new facilities to address and prevent exceedances of the Reclaimed Water Quality Standards ("Additional Facilities"). Additional Facilities, if required by the County, will be paid for by the County.

(ii) If there are no exceedances of the Upper Limits of the Reclaimed Water Quality Standards specified in Exhibit A, Table A-1, over a period of three (3) months following execution of the activities indicated in the second recovery plan, the count of exceedances will reset to zero. If, however, exceedances persist it will be deemed a County Event of Default, as described in Section 9.01(c).

6.05 Exceedence of Sentinel Limits (Table A-2).

(a) If there is an exceedance of any of the Sentinel Limits (Table A-2), more than three (3) times in any rolling six (6) month period that is confirmed by the County through its own resampling and analysis, FPL will notify the County and the County shall, within twenty (20) days of its receipt of such notice, submit a report that will identify the root cause, potential for continued exceedances and steps to be taken to prevent future exceedances, if such steps are possible. If the issue can be addressed by reasonable process adjustments or other mitigating steps within the SDWWTP facility and at no additional costs, such changes or mitigating steps will be taken.

(b) If there are no exceedances of the Sentinel Limits (Table A-2), over a period of three (3) months following execution of the activities indicated in the County's recovery plan, the count of exceedances will reset to zero. If, however, exceedances persist or the County report of Section 6.04(a) identifies no mitigating action can be taken by the County, the County and FPL will jointly determine what Additional Facilities could be added to SDWWTP operations or the ARWP to address the exceedances.

(c) The recovery plan(s) may include new facilities to address and prevent exceedances of the Reclaimed Water Quality Standards ("Additional Facilities"). The capital costs of Additional Facilities under this Section 6.04, if required, will be equally shared by the County and FPL.

6.06 Notice. If FPL must stop receiving all or any portion of the Reclaimed Water because it fails to meet the Reclaimed Water Quality Standards or the Sentinel Limits, it shall notify the County as soon as is reasonably practicable, per the notification requirements of Section 7.06.

ARTICLE VII.
OPERATIONS, MAINTENANCE & METERING

7.01 Generally. FPL will ensure that the FPL Facilities will be operated and maintained, and related additions and repairs made, in accordance with prudent industry practice and in compliance with all applicable water quality and environmental protection regulations in the governing permits and authorizations for the ARWP. Further, FPL will ensure operations are conducted in accordance with the Operating Agreement.

7.02 Staffing. FPL shall provide sufficient qualified staff and resources to operate the FPL Facilities in normal and reasonably anticipated atypical modes.

7.03 Emergencies. Notwithstanding any other provision in this Agreement, FPL may take any action it reasonably believes is necessary to address a situation or circumstance that threatens the safe or reliable operation of the Project, threatens to cause damage to the Project or a portion thereof or as required to comply with applicable laws or regulations, in accordance with prudent industry practice and using commercially reasonable efforts to keep its annual O&M costs within the Operating Budget.

7.04 Water Quality Testing.

(a) FPL and the County shall include in the Operating Agreement of Section 5.03, a sampling plan to facilitate the following:

(b) Periodic sampling by FPL and the County and analysis of influent Reclaimed Water to determine whether such Reclaimed Water meets the Reclaimed Water Quality Standards and Sentinel Limits, as set forth in Exhibit A. The sampling plan shall include sampling frequency and define sample collection points. Sampling methodologies and laboratory analysis shall be in accordance with applicable state and federal regulations or best practices as applicable.

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Standard analytical methods and certified laboratories shall be used at all times to determine water quality and the County shall have the right to conduct its own testing to verify water quality.

(c) FPL shall conduct all required testing of Process Water effluent from the Project to demonstrate compliance with all applicable permits, approvals and authorizations.

7.05 Metering.

(a) FPL shall, at its own expense, own, install, operate and maintain any required flow meters and associated measuring and recording equipment (the "**Meter**") necessary to provide an accurate determination of the quantities of Reclaimed Water, delivered daily under this Agreement and make available to the County, at no cost to the County, all of the data from such Meter. The Meter(s) shall indicate flow with an error not to exceed plus or minus 2% of full scale reading ("**True Accuracy**"); and

(b) FPL shall exercise reasonable care in the maintenance and operation of the Meter(s) so as to assure to the maximum extent reasonably practicable an accurate determination of the quantities of Reclaimed Water delivered under this Agreement; and

(c) The accuracy of the FPL's Meter(s) shall be tested and verified by FPL and the County, at FPL's sole expense, once every six months. FPL shall provide the results of the verification to the County no later than thirty (30) days after each Meter is checked. If the County desires to be present for such Meter checks, it shall be the County's responsibility to contact FPL and make arrangements to be present.

7.06 Notification of abnormal conditions. If abnormal conditions prevent the County from delivering all or a portion of the Maximum Daily Quantity, or meeting the Quality Standards, County will notify FPL as soon as practicable. If abnormal conditions prevent FPL from receiving all or a portion of the Maximum Daily Quantity, FPL will notify County as soon as practicable. The parties will use all reasonably practicable efforts to expedite a return to normal operations.

ARTICLE VIII.
COMPENSATION & PAYMENT

8.01 Annual Fee. Commencing on the Service Initiation Date and for the term of this Agreement, County shall pay to FPL, an annual fee in the amount of $6.5 million. FPL shall invoice the County for the annual fee by June 1 of each year, and the County will make payment within 45 days of receipt of the invoice. The initial and final invoices shall be prorated according to the number of days of service between the Service Initiation Date and June 1 for the initial invoice and for the number of days of service from June 1 to the termination of the agreement for the final invoice.

ARTICLE IX.
EVENTS OF DEFAULT

9.01 County Events of Default. Each of the following shall constitute an event

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of default by the County (each a "**County Event of Default**"):

(a) the County fails to provide support reasonably required for the County to carry out its obligations set forth in this Agreement;

(b) the County fails to make a payment due to FPL that is not subject to a good-faith dispute within forty-five (45) calendar days after notice from FPL that such payment is due under this Agreement;

(c) the Reclaimed Water has failed to meet the Upper Limits of the Reclaimed Water Quality Standards as described in Exhibit A, Table A-1, and the recovery plans of Section 6.03 have not resolved the issue(s);

(d) The County fails to achieve any of its milestones necessary to complete or operate the ARWP; provided, it shall not be considered a default of the County if the failure to achieve such milestone is caused by force majeure or by a failure on the part of FPL in the performance of its milestones;

(e) If, during any month following the Service Initiation Date, the County fails, for ten (10) consecutive calendar days or fifteen (15) days in any thirty (30) day period, to make available to FPL the quantities of Reclaimed Water in the FPL ARWP Manager's forecast and generally set forth in Exhibit C, and such failure is not excused by reason of Force Majeure; or

(f) The County is in default of any material provision of this Agreement (including water quality provisions) not specifically mentioned in this Section 9.01. and the County has failed to cure such default within ten (10) calendar days after notice of such default from FPL to the County. If it is not feasible to correct such default within ten (10) calendar days after FPL has delivered notice of such default to the County, but it remains feasible to correct within thirty (30) calendar days, and (ii) if within ten (10) calendar days after said notice from FPL, the County provides FPL notice of its intention to cure such default and evidence that it remains feasible to correct such default within thirty (30) calendar days after such notice from FPL, it shall not constitute a County Event of Default hereunder until the earliest feasible date within such thirty (30) calendar days period when a cure could be effected so long as (i) corrective action by the County is instituted within ten (10) calendar days following the notice from FPL, (ii) such corrective action is diligently pursued, (iii) the County provides FPL weekly written reports as to the nature and progress of such corrective action, and (iv) such cure is effected within thirty (30) calendar days of the notice from FPL.

9.02 FPL Events of Default. Each of the following shall constitute an event of default by FPL (each an "**FPL Event of Default**"):

(a) FPL refuses, in writing, to receive the Reclaimed Water and such refusal is not (i) subject to good faith dispute, or (ii) excused by reason of Force Majeure;

(b) FPL is in default of any material provision of this Agreement not specifically mentioned in this Section 9.02. and FPL has failed to cure such default within ten calendar (10) days after notice of such default from the County to FPL. If it is not feasible to correct such default within ten (10) calendar days after the County has delivered notice of such default to FPL, but it remains feasible to correct within thirty (30) calendar days, and if within ten (10) calendar days after said notice from the County, FPL provides the County notice of its intention to cure such default and evidence that it remains feasible to correct such default within thirty (30) calendar days after such notice from the County, it shall not constitute an FPL Event of Default hereunder until the earliest feasible date within such thirty (30) calendar day period when a cure could be effected so long as (i) corrective action by FPL is instituted within ten (10) calendar days following the notice from the County, (ii) such corrective action is diligently pursued, (iii) FPL provides the County bi-weekly written reports as to the nature and progress of such corrective action, and (iv) such cure is effected within thirty (30) calendar days of the notice from the County;

(c) FPL fails to achieve any of its milestones necessary to complete or operate the ARWP; provided, it shall not be considered a default of FPL if the failure to achieve such milestone is caused by force majeure or by a failure on the part of the County in the performance of its milestones

9.03 Remedies for a County Event of Default. Upon the occurrence of any County Event of Default, FPL may, in its sole discretion:

(a) terminate this Agreement without penalty or further obligation to FPL by providing written notice to the County; and

(b) require that the County, and the County covenants that it shall, purchase the FPL Facilities from FPL at book value on terms to be negotiated by the Parties acting in good faith;

(c) exercise any other right or remedy available to FPL under generally applicable law, under this Agreement or in equity.

9.04 Remedies for an FPL Event of Default. Upon the occurrence of any FPL Event of Default, the County may, in its sole discretion:

(a) if the FPL Event of Default occurs pursuant to Section 9.02(a), terminate this Agreement without penalty or further obligation to the County by providing written notice to FPL;

(b) if an FPL Event of Default results from a material non-compliance with applicable water quality and environmental protection regulations in the governing permits and authorizations specifically for the ARWP (Section 7.01), the County may withhold delivery of Reclaimed Water until such material non-compliance is resolved.

(c) exercise any other right or remedy available to the County under generally applicable law, under this Agreement or in equity.

9.05 Specific Performance. In addition to the remedies set forth in Section 9.03 and 9.04, each Party shall be entitled to seek a decree compelling specific performance with respect to, and shall be entitled, without the necessity of filing any bond, to seek the restraint by injunction of any actual or threatened breach of any material obligation of the other Party under this Agreement.

9.06 Pre-Termination Liabilities. No termination under this Article IX (or otherwise under this Agreement) shall affect the liability of either Party for obligations arising prior to such termination or for damages, if any, resulting from breach of this Agreement.

ARTICLE X.
FORCE MAJEURE

10.01 Force Majeure. Except as otherwise provided in this Agreement, each Party shall be excused, pursuant to the procedures set forth in this Article X, from performance of its obligations under this Agreement to the extent its nonperformance is caused by Force Majeure. "**Force Majeure**" shall mean an act of God which includes but is not limited to sudden, unexpected or extraordinary forces of nature such as floods, washouts, storms, fires, earthquakes, landslides, hurricanes, epidemics, explosions or other forces of nature, strikes, lockouts, other industrial disturbances, wars, blockades, acts of terrorism, insurrections, riots, federal, state, or local governmental restrictions, regulations and restraints, military action, civil disturbances, or conditions in federal, state or local permits.

10.02 Notification. In the event of any delay or nonperformance resulting from Force Majeure, the Party suffering an occurrence of Force Majeure shall notify the other of the nature, cause, date of commencement thereof and the anticipated extent of such delay, and shall indicate whether any date(s) for performance may be affected thereby. Such notice shall be given to the other Party as soon as practicable but in no event later than three (3) business days after the claiming Party's awareness of the Force Majeure and shall provide such substantiating documentation as may reasonably be required to verify such event or circumstances and its effects within ten (10) days of such notice. The Party claiming Force Majeure shall notify the other Party of the status of its efforts in such form and with such frequency as the other Party reasonably may request under the circumstances (but not less than weekly). When the Party claiming Force Majeure is able to resume performance of its obligations under this Agreement, such claiming Party shall give the other Party prompt notice to such effect.

10.03 Mitigation. Any Party suffering an occurrence of Force Majeure shall use commercially reasonable efforts to remedy the cause(s) preventing its performance of this Agreement as promptly as possible.

ARTICLE XI.
DISPUTES, VENUE AND GOVERNING LAW

11.01 Disputes. In the event of any dispute, controversy or claim between the Parties arising out of or relating to this Agreement (collectively, a "**Dispute**"), the FPL Plant Manager shall attempt in the first instance to resolve such Dispute through friendly consultations between the Parties. If such consultations do not result in a resolution of the Dispute within fifteen (15) days after notice of the Dispute has been delivered to either Party, then such Dispute shall be referred to the Turkey Point Site Vice President and the Mayor of Miami-Dade County or his/her designee for resolution. If the Dispute has not been resolved within twenty (20) business days after such referral to the Turkey Point Site Vice President and the Mayor of Miami-Dade County or his/her designee , then either Party may pursue all available remedies. The Parties agree to attempt to resolve all Disputes promptly, equitably and in a good faith manner.

11.02 Venue, Relief, Remedies.

(a) Any and all suits brought by either Party shall be instituted and maintained in any court of competent jurisdiction in Miami-Dade County, Florida.

(b) Except with respect to rights and remedies expressly declared to be exclusive in this Agreement, the rights and remedies of the Parties are cumulative and the exercise by any Party of one or more of such rights or remedies shall not preclude the exercise by it, at the same or different times, of any other rights or remedies for the same default or any other default.

(c) Any failure of a Party to exercise any right or remedy as provided in this Agreement shall not be deemed a waiver by that Party of any claim for damages it may have by reason of the default. Any waiver shall be limited to the particular right so waived and shall not be deemed a waiver of the same right at a later time or of any other right under this Agreement. Waiver by either Party of any breach of any provision of this Agreement shall not be considered as or constitute a continuing waiver or a waiver of any other breach of the same or any other provision of this Agreement.

11.03 Governing Law. This agreement shall be governed by and construed according to the laws of the State of Florida.

ARTICLE XII.
INDEMNIFICATION; LIMITATION OF LIABILITY

12.01 Indemnification. FPL and the County shall each be responsible for its own facilities, for protection of its own systems, and for ensuring adequate safeguards for FPL and the County customers, and the personnel and equipment of the County and FPL. To the extent permitted by law, and subject to the limitations set forth in Section 768.28, F.S., the County shall indemnify, defend and hold FPL harmless, and FPL shall indemnify, defend and hold the County harmless, from any and all claims, demands, costs or expenses, for loss, damage or injury to persons or property caused by, arising out of, or resulting from: (a) any act or omission by the respective Party or that Party's contractors, agents, servants and employees in connection with the development, construction or operation of that Party's facilities or systems, or the operation thereof in connection with the other Party's facilities or systems, (b) any defect in, failure of, or fault related to, a Party's facilities or systems, or (c) the negligence of the respective Party or negligence of that Party's contractors, agents, servants or employees. The respective Party shall pay all claims, costs, damages and losses in connection with (a), (b) or (c) above, and shall investigate and defend all claims, suits or actions of any kind or nature in the name of the other Party, where applicable, including appellate proceedings and shall pay all costs, judgment and attorney's fees that may issue thereon. The foregoing indemnification shall not constitute a waiver of sovereign immunity beyond the limits set forth in Section 768.28, F.S., nor shall the same be construed to constitute agreement by either Party to indemnify the other Party for such other Party's negligent, willful, or intentional acts or omissions. The provisions of this Section 12.01 shall survive termination, cancellation, suspension, completion or expiration of this Agreement.

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12.02 Limitation of Liability. To the fullest extent permitted by law, neither the County nor FPL, nor their respective officers, directors, agents, employees, members, parents, subsidiaries or affiliates, successors or assigns, or their respective officers, directors, agents, employees, members, parents, subsidiaries or affiliates, successors or assigns, shall be liable to the other Party or their respective officers, directors, agents, employees, members, parents, subsidiaries or affiliates, successors or assigns, for claims, suits, actions or causes of action for incidental, indirect, special, punitive, multiple or consequential damages connected with or resulting from performance or non-performance of this agreement, or any actions undertaken in connection with or related to this agreement, including without limitation, any such damages which are based upon causes of action for breach of contract, tort (including negligence and misrepresentation), breach of warranty, strict liability, statute, operation of law, under any indemnity provision or any other theory of recovery. If no remedy or measure of damages is expressly provided herein, the obligor's liability shall be limited to direct damages of up to One Million Dollars ($1,000,000) for each such breach, and such direct damages shall be the sole and exclusive measure of damages and all other remedies or damages at law or in equity are waived; provided, however, that this sentence shall not apply to limit the liability of a party whose actions giving rise to such liability constitute gross negligence or willful misconduct. The provisions of this Section 12.02 shall apply regardless of fault and shall survive termination, cancellation, suspension, completion or expiration of this contract. Nothing contained in this agreement shall be deemed to be a waiver of a Party's right to seek injunctive relief

12.03 No Liability for Exercise of Police Power. Notwithstanding and prevailing over any contrary provision in this Agreement, nothing in this Agreement shall bind the County, the Department of Regulatory and Economic Resources or successor department, or any other County, federal, or state department or authority, committee, or agency: to grant or leave in effect any environmental permit approvals, zoning changes, variances, permits, waivers, contract amendments, or any other approvals that may be granted, withheld, or revoked in the discretion of the County or other applicable Governmental Bodies in the exercise of its police power; or to withhold, revoke, or modify any actions taken by the County or other applicable Governmental Bodies to enforce ordinances, regulations, or other laws, including, without limitation, the Consent Agreement entered into on October 7, 2015, between FPL and the County, through its Department of Regulatory and Economic Resources, Division of Environmental Resources Management, regarding the Cooling Canal System located at Turkey Point. The County shall be released and held harmless by FPL from any liability, responsibility, claims, consequential or other damages, or losses to FPL or to any third parties resulting from denial, withholding, or revocation (in whole or in part) of any such approvals of any kind or nature whatsoever. This limitation on liability for the exercise of the County's police power shall specifically, and without limitation, prevail over the County obligations in this Agreement: to cooperate with the development, permitting and construction of the ARWP;; to execute documents or give approvals, regardless of the purpose required for such execution or approvals; to apply for or assist FPL in applying for any County or third party permit or needed approval; and to contest, defend against, or assist FPL in contesting or defending against any challenge of any nature.

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ARTICLE XIII.
MISCELLANEOUS

13.01 Assignment, or Sale, Etc. Neither the County nor FPL may assign any of its rights or obligations under this Agreement without the prior written consent of the other Party; provided, that without the prior consent of FPL, the County may assign its rights and interests under this Agreement to a financial institution as collateral security, or create a security interest in favor of the financial institution over its rights and interests in this Agreement. Any attempt by a Party to make any assignment, sale, lease, transfer or other disposition described in this Section 13.01 shall be void *ab initio*.

13.02 Notice. All notices required under this Agreement shall be in writing unless expressly specified otherwise herein, and shall be delivered in person, by registered or certified mail or by a nationally recognized overnight courier, return receipt requested, or by facsimile transmission or electronic mail, if an electronic mail address is provided, with confirmation by voice or automatic answer-back service promptly following such facsimile transmission or electronic mail, as specified below:

As to the County:

Miami-Dade County

c/o The Director

Miami-Dade Water and Sewer Department

3071 SW 38th Avenue

Miami, Florida 33146

Facsimile: (786) 552-8647

With a copy to:

Miami-Dade County Attorney

111 NW First St. Suite 2810

Miami, Florida 33128

As to FPL:

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Florida Power & Light Company

c/o Site Vice-President of Turkey Point

With a copy to:

Florida Power & Light Company

Law Department (Law/JB)

c/o Managing Attorney—Commercial Transactions

700 Universe Boulevard

Juno Beach, Florida 33408

Facsimile: (561) 691-7305

Notices shall be effective upon receipt; provided, that in the event a Party fails to notify the other of the correct person and address for notices pursuant to this Section 13.02, any notice to that Party shall be deemed effective on the third day following the date such notice is sent to the person and address last provided by such Party. Either Party may, at any time, by notice designate any different person(s) or different address(es) or phone number(s) for receipt of notices and correspondence.

13.03 Amendments. This Agreement shall not be amended or modified, and no waiver of any provision hereof shall be effective, unless set forth in a written instrument authorized and executed by the Parties. This Agreement, as it may be amended from time to time, shall be binding upon, and inure to the benefit of, the Parties respective successor-in-interest and permitted assigns.

13.04 Survival. The obligations, rights, and remedies of the Parties hereunder, which by their nature survive the termination of this Agreement, shall survive such termination and inure to the benefit of the Parties.

13.05 Construction of Agreement. The Parties expressly agree that no provision of this Agreement should be construed against or interpreted to the disadvantage of any Party by any court or other governmental or judicial authority by reason of such Party having been deemed to have structured or dictated such provision.

13.06 No Third Party Beneficiaries. Nothing in this Agreement, express or implied, is intended to confer upon any person other than the Parties and their permitted successors and assigns any right or remedies under or by reason of this Agreement as a third-party beneficiary or otherwise except as specifically provided in this Agreement.

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13.07 Complete Agreement. This Agreement is intended as the complete and exclusive statement of the agreement with respect to the subject matter hereof between the Parties. Parol or extrinsic evidence shall not be used to vary or contradict the express terms of this Agreement and recourse may not be had to alleged prior drafts, negotiations, prior dealings, usage of trade, course of dealing or course of performance to explain or supplement the express terms of this Agreement. Except as specifically set forth in this Agreement, there shall be no warranties, representations or other agreements among the Parties in connection with the subject matter.

13.08 Relationship of Parties. The Parties understand and agree that no Party is an agent, employer, contractor, vendor, representative or partner, that (expect as expressly set forth in writing) no Party shall owe a fiduciary duty to any other Party, that no Party shall hold itself out as such to third parties and that no Party is capable of binding any other Party to any obligation or liability withiout the prior written consent of the other Party. Neither the execution and delivery of this Agreement, nor consummation of the transactions contemplated hereby, shall create or constitute a partnership, joint venture or any other form of business organization or arrangment among the Parties.

13.09 Representations and Warranties. Each Party represents and warrants that (a) it is an entity duly organized, validly existing and in good standing under the laws of the juridiction in which it is organized and is qualified to do business in all jurisdictions where it is required to be qualified; (b) it has the necessary power and authority to enter into and perform its obligations under this Agreement; (c) it has duly authorized the person(s) signing this Agreement to execute this Agreement on its behalf; and (d) the execution and delivery of this Agreement and its peformance by such Party will not violate, result in a breach of or conflict with any law, rule, regulation order or decree applicable to such Party, its organizational documents or the terms of any other agreement binding on such Party.

13.10 Compliance with Certain Legal Requirements. Each Party shall comply and cause its contractors and consultants to comply with Applicable Laws in performing their respective duties, responsibilities and obligations pursuant to this Agreement. The Parties shall not unlawfully discriminate in the performance of their respective duties under this Agreement. Such laws include but are not limited to the following: Miami-Dade County Resolution No. R-385-95, which creates a policy prohibiting contracts with firms violating the Americans with Disabilities Act of 1990 ("ADA") and other laws prohibiting discrimination on the basis of disability, Miami-Dade County Ordinance No. 72-82 (Conflict of Interest), Resolution No. R-1049-93 (Affirmative Action Plan Furtherance and Compliance), Resolution No. R-185-00 (Domestic Leave Ordinance) and Ordinance No. 02-68 (Security).

13.11 Inspector General. FPL acknowledges that the Office of the Miami-Dade County Inspector General ("IG") has the authority and power to review past, present and proposed County programs, accounts, records, contracts and transactions pursuant to Section 2-1076 of the Miami-Dade County Code.

13.12 Audit. The County retains the right to audit and access all relevant non-proprietary files, correspondence and documents directly related to the cost of the work performed under this Agreement.

EXECUTION VERSION

13.13 Public Records. FPL acknowledges that the County, as a public entity, is subject to Florida's public records law. Said law establishes a right of access to any public record made or received in connection with the official business of any public body, except those records specifically exempted or made confidential by Florida law. The County agrees to use reasonable efforts to notify FPL of any request for disclosure. Failure of FPL to provide written objection to such disclosure within 48 hours shall be considered a waiver of any confidentiality to the requested information and consent to the disclosure. In the event FPl objects to the disclosure, FPL shall within 48 hours of notice to seek an injunction restricting the disclosure of the information. This provision shall survive ttermination of this Agreeement.

13.14 General Interpretative Provisions. Whenever the context may require, terms used in this Agreement shall include the singular and plural forms, and any pronoun shall include the corresponding masculine and feminine forms. The term "including", whenever used in any provision of this Agreement, means including but without limiting the generality of any description preceding or succeeding such term. Each reference to a Person or Party shall include reference to such Person or Party's successors and assigns. All references to "Sections" shall be references to the Sections to this Agreement, except to the extent that any such reference specifically refers to another document. Each of the Parties has agreed to the use of the particular language of the provisions of this Agreement and any questions of doubtful interpretation shall not be resolved by any rule or interpretation against the draftsman.

13.15 No Waiver. Any waiver by either Party of its rights with respect to a default (including Events of Default) under this Agreement, or with respect to any other matters arising in connection with this Agreement, shall not be deemed a waiver with respect to any subsequent default (including Events of Default) or other matter. The failure of either Party to enforce strict performance by the other Party of any of the provisions of this Agreement or to exercise any rights under this Agreement shall not be construed as a waiver or relinquishment to any extent of such Party's right to assert or rely upon any such provisions or rights in that or any other instance.

13.16 Integration. This Agreement contains the entire Agreement of the parties with respect to the subject matter and replaces and supersedes all prior agreements or understandings, oral or written, with respect to such subject matter, and such agreements or understandings are now void and no longer in effect.

13.17 Severability. If any Section of this Agreement is found by a court of competent jurisdiction to be null and void, the other Sections shall remain in full force and effect and the Parties shall work in good faith to renegotiate the provisions found to be null and void so that they (i) comply with the law, and (ii) maintain the commercial and legal benefits and obligations of each Party as originally negotiated for as much as is practicable.

13.18 Preparation. Each Party shall bear its own costs and expenses (including fees of counsel and outside advisors) in connection with the preparation, negotiation and execution of this Agreement and in connection with performing its obligations under this Agreement.

13.19 Counterparts. This Agreement may be executed and delivered in counterparts, and may be delivered by facsimile transmission.

EXECUTION VERSION

IN WITNESS WHEREOF, the County and FP&L have executed this Agreement acknowledging their mutual agreement thereto and the obligations and requirements contained herein.

ATTEST:

Harvey Ruvin, Clerk

Olga Valverde

Deputy Clerk

COUNTY COMMISSIONERS MIAMI-DADE COUNTY FLORIDA

MIAMI-DADE COUNTY, a political subdivision of the State of Florida

By: 07/06/2020

Carlos Gimenez

Mayor

MAURICE L. KEMP
DEPUTY MAYOR
MIAMI-DADE CTY. FL

FLORIDA POWER & LIGHT COMPANY, a Florida corporation

By: Olga Valverde, Clerk
[NAME]
[Title]

By:
Eric Silagy
President & CEO
Florida Power & Light Company

STATE OF Florida
COUNTY OF Palm Beach

The foregoing instrument was acknowledged before me by means of: (check one) ✓ physical presence; or ___ remote audio-visual means, this 29th day of May 2020, by Eric Silagy, as President, and ________________, as Secretary, of FPL, a ________________, on behalf of the corporation. He/She/They is/are personally known to me or has/hasn't/have/haven't produced identification and did/did not take an oath.

Notary Public

GG322672
Serial Number

Debra Neger
Print Name

DEBRA A. NEGER
Notary Public - State of Florida
Commission # GG 322672
My Comm. Expires Jul 10, 2023
Bonded through National Notary Assn.

EXECUTION VERSION

Exhibit A

Table A-1 Reclaimed Water Quality Standards

Parameter	Units	Target Value	Upper Limit
TSS	mg/l	5	20
pH	units	6.0 – 8.0	8.5

Table A-2 Sentinel Limits

Parameter	Units	Limit
TDS	mg/L	500
Chloride	mg/L	160
Alkalinity (as CaCO3)	mg/L	250
Total Phosphorous	mg/L	4.0
Ammonia (as N)	mg/L	35
Nitrate	mg/L	3.5
Nitrite	mg/L	2.5
Magnesium (as Mg)	mg/L	20
Sodium	mg/L	210

Notes:

1. Persistent production of Reclaimed Water in excess of Upper Limits of Table A-1 that is not resolved by a recovery plan is a County Event of Default, as described in paragraph 9.01(c).

2. Standard frequency of testing for each parameter will be established by FPL and the County in the sampling plan, that will be part of the Operating Agreement as described in paragraph 5.03. The Sentinel Limits will be reviewed when the sampling plan is developed to verify the appropriateness of these limits in relation to the final ARWP design and final permits and authorizations.

3. The County will fully cooperate on monitoring other water quality parameters that are important to the effective operation of the Advanced Reclaimed Water Treatment System but which are not regulated or treated at the South District Wastewater Treatment Plant.

EXECUTION VERSION

Exhibit B
Delivery Point, FPL Facilities and County Facilities

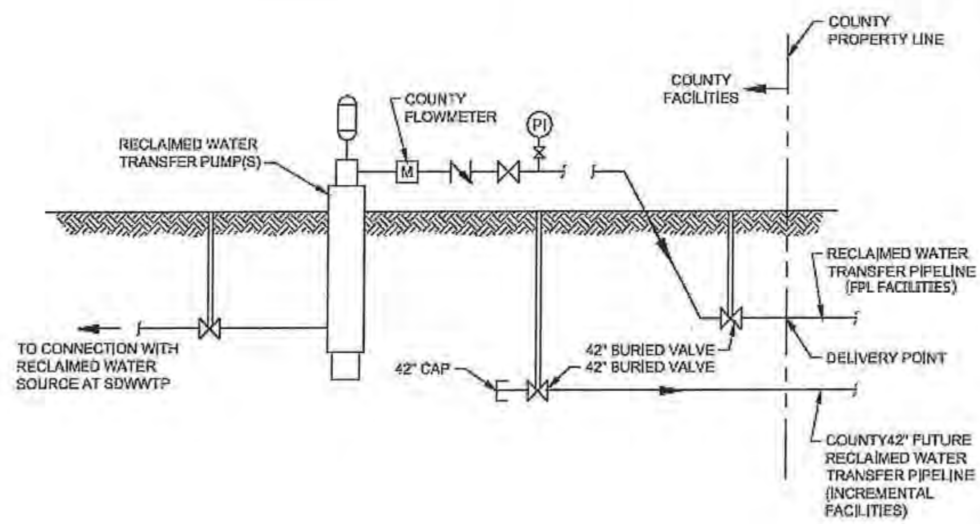

FIGURE B-1
COUNTY, FPL AND INCREMENTAL FACILITIES AND DELIVERY POINT FOR TRANSFER OF RECLAIMED WATER

Notes:

1. County Facilities include the Reclaimed Water transfer pumps and motors, transfer piping, valves, instruments and electrical components on SDWWTP property including the buried 42" valve adjacent to the SDWWTP Property Line (Delivery Point). County Facilities also includes the Incremental Facilities necessary to provide additional pipeline capacity of up to 60 MGD for Reclaimed Water transport to the Turkey Point site. Incremental Facilities will include a parallel 42" pipeline and related components and will terminate 10' inside the TP Complex property line and 10' inside the SDWWTP property line.

2. FPL Facilities include the Reclaimed Water transfer pipeline from the SDWWTP property line to the FPL treatment facilities at Turkey Point, the FPL treatment facilities and associated Process Water and Process Wastewater pipelines and equipment, the

cooling tower basins, the deep injection well facilities on the Turkey Point site, and, possibly, on-site Process Wastewater disposal.

EXECUTION VERSION

Exhibit C

Delivery and Coordination Requirements

Parameter	Quantity
Maximum Daily Quantity (MGD):	15 MGD
Average Daily Quantity (MGD):	9 MGD
Minimum Daily Quantity (MGD):	3.5 MGD
Rate of Change Limit (gpm/hour):	Note 1
Measurement Methodology at Delivery Point:	Note 1

Note 1. An Operating Agreement (Section 5.03 of the Agreement) will be developed in conjunction with the permitting and final design of the ARWP to describe the responsibilities of the Parties in regards to coordinated operations and maintenance of the FPL and County Facilities.

EXECUTION VERSION

Exhibit D

Conditions Precedent & Sequence of Events

A. Conditions Precedent:

1. FPL receives approval / assurance that the costs incurred in connection with the FPL Facilities can be recovered.
2. FPL receives Subsequent License Renewal Approval for Turkey Point Units 3 & 4.
3. County receives approval / assurance that it will receive the appropriate reclaimed credits for the project in accordance with Section 403.064, Florida Statutes for the duration of this Agreement.
4. FPL and County receive necessary and appropriate permits, approvals and authorizations from regulatory authorities that support execution of the project. Examples include modifications to any existing permit, authorization or certification that are necessary to proceed with the project.
5. FPL and County receive the necessary and appropriate approvals from the respective authorizing entities; NextEra Energy Board of Directors and Miami-Dade County Board of County Commissioners.

B. Expected Sequence of Events:

1. FPL receives Subsequent License Renewal Approval for Units 3 & 4. (December 2019).
2. The Reclaimed Water Service Agreement is presented to FPL management and Miami-Dade County Board of County Commissioners for approval (Summer 2020).
3. Upon Board of County Commission and FPL management approval, FPL and County execute the Reclaimed Water Service Agreement (Summer 2020), subject to any applicable or necessary regulatory approvals.
4. FPL obtains assurance that it can recover the costs it incurs in connection with the Reclaimed Water Service Agreement (Fall 2021).
5. FPL and County identify and obtain all necessary permits, modifications to existing permits, authorizations, or certifications to proceed with project
6. FPL and County commence detailed design, engineering and initiate permitting

process.

7. FPL and County complete cost and schedule estimates for their respective facilities, in accordance with the Reclaimed Water Service Agreement.

8. FPL and the County commence construction of FPL and County Facilities in accordance with the terms of the Reclaimed Water Service Agreement.

9. FPL and the County develop the Operations Agreement reflecting the ARWP final design, permits, approvals and authorizations.

10. FPL and the County complete construction of the FPL and County Facilities.

11. FPL test period with intermittent delivery of Reclaimed Water from County.

12. Full delivery of Reclaimed Water for processing into Processed Water and utilization at the TP Complex commences (NLT 12/31/2025).

STATE OF FLORIDA

DEPARTMENT

OF

ENVIRONMENTAL PROTECTION

Conditions of Certification

Florida Power & Light Company
Turkey Point Plant
Units 3 and 4 Nuclear Power Plant
Unit 5 Combined Cycle Plant

PA 03-45E

03/29/2016

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List of Exhibits

List of Appendices

I. CERTIFICATION CONTROL

A. Pursuant to s. 403.501-518, F.S., the Florida Electrical Power Plant Siting Act, this certification is issued to Florida Power & Light Company (FPL) as owner/operator of the Turkey Point Plant. The Department recognizes that Nuclear Units 3 & 4 and Fossil Unit 5 are under the control of different divisions of FPL. Unless otherwise specified, FPL shall be responsible for the compliance with the conditions herein. Violation of any conditions specific to Units 3, 4, or 5 shall solely affect the license of the responsible generating units. Under the control of these Conditions of Certification FPL may operate a 1,150 MW (nominal) facility (Unit 5) consisting of four 170 MW natural gas fired combustion turbines with light oil as back-up fuel, four heat recovery steam generators and one 470 MW steam turbine, and one nuclear plant consisting of two 800 MW (nominal) pressurized water reactors (Units 3 & 4), and all ancillary equipment. Unit 5 is located on approximately 90 acres of the existing 11,000 acres Turkey Point site in Miami-Dade County, Florida. Units 3 & 4 are located on approximately 30 acres of the existing site.

B. These Conditions of Certification, unless specifically amended or modified, are binding upon the Licensee and shall apply to the construction and operation of the certified facility. If a conflict should occur between the design criteria of this project and the Conditions of Certification, the Conditions shall prevail unless amended or modified. In any conflict between any of these Conditions of Certification, the more specific condition governs.

II. APPLICABLE RULES

The construction and operation of the certified facility shall be in accordance with all applicable provisions of Florida Statutes and Florida Administrative Code, including, but not limited to, the following regulations: Chapters 403 and 373, Florida Statutes (F.S.); South Florida WMD Chapters 40E-1, 40E-2, 40E-3, 40E-4, 40E-8, 40E-21, 40E-40, 40E-45; and 62-4, 62-17, 62-256, 62-296, 62-297, , 62-302, 62-520, 62-531, 62-532, 62-330, 62-550, 62-555, 62-560, 62-600, 62-601, 62-604, 62-610, 62-620, 62-621, 62-650, 62-660, 62-699, 62-701, 62-762, 62-769, 62-777, and 62-780, Florida Administrative Code (F.A.C.), or their successors as they are renumbered.

III. DEFINITIONS

The meaning of terms used herein shall be governed by the definitions contained in Chapters 373 and 403, Florida Statutes, and any regulation adopted pursuant thereto. In the event of any dispute over the meaning of a term used in these conditions which is not defined in such statutes or regulations, such dispute shall be resolved by reference to the most relevant definitions contained in any other state or federal statute or regulation or, in the alternative by the use of the commonly accepted meaning as determined by the Department. -As used herein:

A. "Applications" shall mean the Site Certification Applications (SCAs) for the certified facilities, as supplemented.

B. "DEO" shall mean the Florida Department of Economic Opportunity.

C. "DEP" or "Department" shall mean the Florida Department of Environmental Protection.

D. “DERM” shall mean the Department of Environmental Resources Management of Miami-Dade County, Florida.

E. "DHR" shall mean the Florida Department of State, Division of Historical Resources.

F. "Emergency conditions" shall mean urgent circumstances involving potential adverse consequences to human life or property as a result of weather conditions or other calamity, and necessitating new or replacement gas pipeline, transmission lines, or access facilities.

G. “Facility” shall mean the certified electrical power generation facilities and all associated structures, including but not limited to: nuclear steam generating units, combined cycle generating units, team turbine generators, transformers, substations, fuel and water storage tanks, air and water pollution control equipment, storm water control ponds and facilities, cooling towers, and related structures.

H. "Feasible" or "practicable" shall mean reasonably achievable considering a balance of land use impacts, environmental impacts, engineering constraints, and costs.

I. "FWCC" shall mean the Florida Fish and Wildlife Conservation Commission.

J. “IWW Permit” shall mean the Florida Industrial Wastewater permit issued by the Department in accordance with the federal Clean Water Act.

K. "Licensee" shall mean an applicant which has obtained a certification order for the subject electrical power plant.

L. “NPDES permit” shall mean any federal National Pollutant Discharge Elimination System permit issued in accordance with the federal Clean Water Act.

M. “NRC” shall mean Nuclear Regulatory Commission.

N. “NSPS” shall mean new source performance standards as identified in 40 CFR 60.

O. "Power plant", "facility", or "project" shall mean an electrical power generating plant as defined in Section 403.503(12), F.S. and as described in the Site Certification Application.

P. “PSD permit” shall mean the federal Prevention of Significant Deterioration air emissions permit issued in accordance with the federal Clean Air Act.

Q. “SED” shall mean the Department’s Southeast District Office.

R. "SFWMD" shall mean the South Florida Water Management District.

S. “Title III permit” shall mean any federal permit issued in accordance with Title III of the federal Clean Air Act (Hazardous Air pollutants).

T. “Title IV permit” shall mean any federal permit issued in accordance with Title IV of the federal Clean Air Act (Acid Rain).

U. "Title V permit" shall mean any federal permit issued in accordance with Title V of the federal Clean Air Act (Operation).

V. "WASD" shall mean the Water and Sewer Department of Miami-Dade County, Florida.

IV. GENERAL CONDITIONS

These General Conditions shall be applicable to all areas of the certified site. Compliance with the General Conditions shall be the joint responsibility of FPL Nuclear Plant (Units 3 &4) and FPL Fossil Fuel Plant (Unit 5). Any violation of a General Condition shall be a violation by Florida Power & Light Company.

A. Facilities Operation

The Licensee shall at all times properly operate and maintain the Turkey Point Unit 3, 4 and 5 facilities and related appurtenances, and systems of treatment and control that are installed and used to achieve compliance with the conditions of this certification, and are required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the approval and when required by Department rules.

Any directly associated linear facilities connecting the collector yard to the switchyard shall be maintained in accordance with the site certification application and any appropriate state and federal regulations concerning use of herbicides. The Licensee shall notify the Southeast District of the Department and the Siting Coordination Office of the type of herbicides to be used at least 60 days prior to their first use.

B. Records Maintained at the Facility

1. These Conditions of Certification or a copy thereof shall be kept at the work site of the approved activity.

2. The Licensee shall hold at the facility, or other location designated by this approval, records of all monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation required by this approval, copies of all reports required by this approval, and records of all data used to complete the application for this approval. These materials shall be retained at least three (3) years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule. The Licensee shall provide copies of these records to the Department upon request. If the Licensee becomes aware of relevant facts that were not submitted or were incorrect in any report to the Department, such facts or information shall be promptly submitted or corrected.

C. Change in Discharge or Emissions

All discharges or emissions authorized herein shall be consistent with the terms and conditions of this certification. The discharge or emission of any pollutant not identified in the application, or more frequently than, or at a level in excess of that authorized herein, shall constitute a violation of the certification. Any anticipated facility expansions, production increases, or process modifications which may result in new, different or increased discharge or emission of pollutants, change in fuel, or expansion in steam generating capacity must be reported by submission of an appropriate application for amendment, certification or modification pursuant to Chapter 403.516, F.S.

D. Compliance

1. The Licensee shall comply with all rules adopted by the Department subsequent to the issuance of this certification, which prescribe new or stricter criteria to the extent that the rules are applicable to electric power plants. Except where express variances have been granted, subsequently adopted rules which prescribe new or stricter criteria, which are applicable to electrical power plants, shall operate as a modification pursuant to Section 403.511(5)(a), F.S.

2. Pursuant to Section 403.511(5)(b), F.S., upon written notification to the Department's Siting Coordination Office, the Licensee may choose to operate in compliance with any rule subsequently adopted by the Department which prescribes criteria more lenient than the criteria required by the terms and conditions in this certification, so long as this operation causes no violation of standards or these Conditions of Certification.

3. If, for any reason, the Licensee does not comply with or is unable to comply with any limitation specified in this certification, the Licensee shall notify the Southeast District Office of the Department by telephone during the working day that said noncompliance occurs. After normal business hours, the Licensee shall report any condition that poses a public health threat to the State Warning Point at telephone number (850) 413-9911 or (850) 413-9912. The Licensee shall confirm this situation to the Southeast DEP District Office in writing within seventy-two (72) hours of becoming aware of such conditions and shall supply the following information:

a. A description of the discharge and cause of noncompliance; and,

b. The period of noncompliance, including exact dates and times; or, if not corrected, the anticipated time the noncompliance is expected to continue, and,

c, Steps being taken to reduce, eliminate and prevent recurrence of the non-complying event.

4, The Licensee shall take all reasonable steps to minimize any adverse impact resulting from noncompliance with any limitation specified in this certification, including such accelerated or additional monitoring as necessary to determine the nature and impact of the non-complying event.

E. Right of Entry

The Licensee shall allow authorized agency personnel, including but not limited to representatives of the Florida Department of Environmental Protection, and/or Water Management District, when applicable, upon presentation of credentials or other documents as may be required by law, and at reasonable times, and recognizing the security that must be maintained at the facility, depending upon the nature of the concern being investigated:

1. To enter upon the Licensee's premises where an effluent source is located or in which records are required to be kept under the terms and conditions of this permit; and

2. To have access to and copy any records required to be kept under the conditions of this certification; and

3. To inspect the facilities, equipment, practices, or operations regulated or required under these Conditions; and

4. To sample or monitor any substances or parameters at any location necessary to assure compliance with these Conditions of Certification or Department rules.

F. Enforcement

1. The terms, conditions, requirements, limitations and restrictions set forth in these Conditions of Certification are binding and enforceable pursuant to Sections 403.141, 403.161, 403.514, 403.727, and 403.859 through 403.861, F.S. Any noncompliance with a condition of certification or condition of a federally delegated or approved permit constitutes a violation of chapter 403, F.S., and is grounds for enforcement action, permit termination, permit revocation, or permit revision. The Licensee is placed on notice that the Department will review this certification periodically and may initiate enforcement action for any violation of these conditions.

2. All records, notes, monitoring data and other information relating to the construction or operation of this certified source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the certified source arising under the Florida Statutes or Department rules, except where such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

3. The specific terms of the Fifth Supplemental Agreement and the Revised Plan, referenced in Condition X of these Conditions of Certification, shall remain enforceable by the SFWMD by the terms of the Fifth Supplemental Agreement.

G. Revocation or Suspension

This certification may be suspended or revoked pursuant to Section 403.512, Florida Statutes, or for violations of any of these Conditions of Certification. This approval is valid only for the specific processes and operations identified within the application and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this approval may constitute grounds for revocation and enforcement action by the Department. Any enforcement action, including suspension and revocation, shall only affect the certified facilities that are the cause of such action, and other facilities at the Turkey Point Plant shall remain unaffected by such action.

H. Civil and Criminal Liability

This certification does not relieve the Licensee from civil or criminal penalties for noncompliance with any conditions of this certification, applicable rules or regulations of the Department, or any other state statutes or regulations which may apply. As provided in Section 403.511, F.S., the issuance of this certification does not convey neither any vested rights nor any exclusive privileges. Neither does it authorize any injury to human health or welfare, animal or plant life, public or private property or any invasion of personal rights.

This certification does not allow any infringement of federal, state, or local laws or regulations, nor does it allow the Licensee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department or these Conditions of Certification. This approval is not a waiver of any other Department approval that may be required for other aspects of the total project under federally delegated or approved programs.

I. Property Rights

The issuance of this certification does not convey any property rights in either real or personal property, or any exclusive privileges thereto. The applicant shall obtain title, lease, easement, or right of use from the State of Florida to any sovereign submerged lands utilized by the project.

J. Severability

The provisions of this certification are severable, and if any provision of this certification, or the application of any provision of this certification to any circumstances, is held invalid, the application of such provision to other circumstances and the remainder of the certification shall not be affected thereby.

K. Procedural Rights

No term or condition of certification shall be interpreted to preclude the post-certification exercise by the Licensee of whatever procedural rights it may have under Chapter 120, F.S.

L. Review of Site Certification

The certification shall be final unless revised, revoked or suspended pursuant to law.

M. Procedural Rights

Except as specified in Chapter 403, F.S., or Chapter 62-17, F.A.C., no term or condition of certification shall be interpreted to preclude the post-certification exercise by the licensee of whatever procedural rights it may have under Chapter 120, F.S., including those related to rule-making proceedings.

N. Modification of Conditions

The conditions of this certification may be modified in the following manner:

1. Pursuant to Section 403.516(1), F.S., Section 120.569(2)(n), F.S., and Rule 62-17.211, F.A.C., the Siting Board hereby delegates the authority to the Secretary of the Department of Environmental Protection who further delegates to the Siting Office the authority to modify, after notice and opportunity for hearing, any conditions herein which would not otherwise require approval from the Siting Board

2. The certification shall be modified to conform to subsequent DEP-issued amendments, modifications, or renewals of any separately issued Prevention of Significant Deterioration (PSD) permit, Title V Air Operation permit, Underground Injection Control (UIC) permit, or National Pollutant Discharge Elimination System (NPDES) permit for the project. In

the event of a conflict, the more stringent of the conditions of such permits or of these Conditions of Certification shall be controlling.

3. The Secretary of the Department may modify any condition of this certification except those pertaining to a change in fuel.

4. The Secretary of the Department may modify any condition of this certification if the Secretary finds that an immediate danger to the public health, safety, or welfare requires the issuance of an immediate final order temporarily modifying these Conditions of Certification. If the Secretary elects to exercise this delegated authority, the Secretary shall prepare an immediate final order that recites with particularity the facts underlying the Secretary's finding of an immediate danger to the public health, safety, or welfare. The immediate final order and the modification to the Conditions of Certification shall be effective only for so long as is necessary to address the immediate danger and shall be applicable or enjoinable from the date rendered.

5. In the event of a prolonged [thirty (30) days or more] equipment malfunction or shutdown of pollution control equipment, the Secretary of the Department may allow facility operation to resume and continue to take place under an immediate final order temporarily modifying these Conditions of Certification, provided that the Licensee demonstrates that such operation will be in compliance with all applicable ambient air quality standards and PSD increments, water quality standards and rules, solid waste rules, domestic wastewater rules and industrial wastewater rules. During such malfunction or shutdown, the operation of the facility shall comply with all other requirements of this certification and all applicable state and federal emission and effluent standards not affected by the malfunction or shutdown.

6. All other modifications to these conditions shall be made in accordance with Section 403.516, Florida Statutes.

7. Any modification to these conditions shall only affect the units or other facilities that are the subject of the modification request or the Department’s proposed order of modification.

O. Transfer of Certification

This certification is transferable only upon Department approval in accordance with Section 403.516, F.S., and Rule 62-17.211(3) and 62-730.300, F.A.C. The Licensee shall be liable for any noncompliance of the approved activity until the transfer is approved by the Department.

P. Safety

The overall design, layout, and operation of the facilities shall be such as to minimize hazards to humans and the environment. Security control measures shall be utilized to prevent exposure of the public to hazardous conditions. The applicable Federal Occupational Safety and Health Standards shall be complied with during construction and operation.

Q. Screening

The Licensee shall maintain existing screening of the site to the extent feasible through the use of acceptable structures, vegetated earthen walls, or existing or planted vegetation.

R. Toxic, Deleterious or Hazardous Materials

1. The Licensee shall not discharge to surface waters wastes which are acutely toxic, or present in concentrations which are carcinogenic, mutagenic, or teratogenic to human beings or to significant locally occurring wildlife or aquatic species. The Licensee shall not discharge to ground waters wastes in concentrations which, alone or in combination with other substances, or components of discharges (whether thermal or non-thermal) are carcinogenic, mutagenic, teratogenic, or toxic to human beings or are acutely toxic to indigenous species of significance to the aquatic community within surface waters affected by the ground water at the point of contact with surface waters. Specific criteria are established for such components in Section 62-520.420, F.A.C.

2. The Licensee shall report all spills of materials having potential to significantly pollute surface or ground waters and which are not confined to a building or similar containment structure, by telephone immediately after discovery of such spill. The Licensee shall submit a written report within forty-eight hours, excluding weekends, from the original notification. The telephone report shall be submitted by calling the DEP Southeast District Office Industrial Wastewater Compliance/Enforcement Section. After normal business hours, the Licensee shall contact the State Warning Point by calling (850) 413-9911 or (850) 413-9912. The written report shall include, but not be limited to, a detailed description of how the spill occurred, the name and chemical make-up (include any Material Safety Data Sheets) of the substance, the amount spilled, the time and date of the spill, the name and title of the person who first reported the spill, the size and extent of the spill and surface types (impervious, ground, water bodies, etc.) it impacted, the cleanup procedures used and status of completion, and include a map or aerial photograph showing the extent and paths of the material flow.

3. The Licensee shall notify the Department's Siting Coordination Office of any amendments, modifications, or renewals of NRC-issued Operating Licenses.

S. Noise

Construction and operation noise shall not exceed noise criteria or any applicable requirements of Miami-Dade County. The Licensee shall notify area residents in advance of the onset and anticipated duration of the steam blowout of the facility's heat recovery steam generator and steam lines

T. Flood Control Protection

Any construction of new facilities for the certified plant and associated facilities shall be protected from flood damage by construction in such a manner as to comply with the appropriate Miami-Dade County flood protection requirements or by flood proofing or by raising the elevation of the facilities above the 100-year flood level, whichever is more stringent. However, existing facilities are not required to be modified to comply with such flood control protection standards.

U. Historical or Archaeological Finds

If historical or archaeological artifacts are discovered at any time within the project site, the Licensee shall notify the DEP Southeast District office and the Bureau of Historic Preservation, Division of Historical Resources, R.A. Gray Building, Tallahassee, Florida 32399-0250, telephone number (850) 487-2073.

V. Endangered and Threatened Species

Prior to start of construction, the Licensee shall survey the portion of the certified site which may be affected by construction for species of animal and plant life listed as endangered or threatened by the federal government or listed as endangered by the state. If these species are found, their presence shall be reported to the Siting Coordination Office, the SED, and the Florida Fish & Wildlife Conservation Commission's Office of Policy and Stakeholder Coordination. These species shall not be disturbed, if practicable. If avoidance is not practicable, the endangered species shall be treated as recommended by the appropriate agency. Entombment of gopher tortoises shall not be allowed.

W. Dispute Resolution

If a dispute situation arises between the Licensee and an agency exercising its regulatory jurisdiction, the Department shall act as mediator to resolve it. If, after mediation, a mutual agreement cannot be reached between the parties, then the matter shall be immediately referred to the Division of Administrative Hearings (DOAH) for disposition in accordance with the provisions of Chapter 120, F.S.

X. Laboratories and Quality Assurance

1. The Licensee shall ensure that all laboratory analytical data submitted to the Department, as required by this certification, are from a laboratory which is approved by the Department and meets the requirements of Chapter 62-160, F.A.C.

2. The Licensee shall ensure that all samples required pursuant to this certification are taken by an appropriately trained technician following EPA and Department approved sampling procedures and chain-of-custody requirements in accordance with Rule 62-160, F.A.C. Records of monitoring information shall follow the guidelines in Rule 62-160.600, F.A.C. All chain-of-custody records shall be retained on-site for at least three (3) years and made available to the Department immediately upon request.

3. Records of monitoring information shall include:

   a. the date, exact place, and time of sampling or measurements;

   b. the person responsible for performing the sampling or measurements;

   c. the dates analyses were performed;

   d. the person responsible for performing the analyses;

   e. the analytical techniques or methods used; and,

   f. the results of such analyses.

Y. Procedures for Post-Certification Submittals

1. The licensee shall provide within 90 days after certification a complete summary of those submittals identified in the Conditions of Certification where due-dates for information required of the licensee are identified. Such submittals shall include, but are not limited to, monitoring reports, management plans, wildlife surveys, etc. The summary shall be provided to the Siting Coordination Office and any affected agency or agency subunit to whom the submittal is required to be provided, in a sortable spreadsheet, via CD and hard copy, in the format identified below or equivalent.
(62-17.191, F.A.C.)

Condition Number	Requirement and timeframe	Due Date	Name of Agency or agency subunit to whom the submittal is required to be provided

2. Purpose of Submittals: Conditions of Certification which provide for the post-certification submittal of information to DEP or other agencies by the licensee are for the purpose of facilitating monitoring by the Department of the effects arising from the certified facilities. This monitoring is for DEP to assure, in consultation with other agencies with applicable regulatory jurisdiction, continued compliance with the conditions of certification, without any further agency action.

3. Filings: All post-certification submittals of information by the licensee or copies of applications for separate federal permits which are to be issued by State agencies are to be filed with DEP Siting Office. Copies of each submittal shall also be simultaneously copied to any other agency indicated in the specific conditions requiring the post-certification submittals.

4. Completeness: The DEP shall promptly review each post-certification submittal for completeness. This review shall include consultation with the other agencies receiving the post-certification submittal. For the purposes of this condition, completeness shall mean that the information submitted is both complete and sufficient. If the submittal is found to be incomplete, the licensee shall be so notified. Failure to issue such a notice within forty-five (45) days after filing of the submittal shall constitute a finding of completeness. (62-17.191, F.A.C.)

5. Interagency Meetings: Within sixty (60) days of the filing of a complete post-certification submittal, DEP may conduct an interagency meeting with other agencies which received copies of the submittal. The purpose of such an interagency meeting shall be for the

agencies with regulatory jurisdiction over the matters addressed in the post-certification submittal to discuss whether reasonable assurance of compliance with the conditions of certification has been provided. Failure of any agency to attend an interagency meeting shall not be grounds for DEP to withhold a determination of compliance with these conditions nor to delay the time frames for review established by these conditions.

6. Reasonable Assurance of Compliance: Within ninety (90) days of the filing of a complete post-certification submittal, unless another date is specified herein, DEP shall give written notification to the licensee and the agencies to which the post-certification information was submitted of its determination whether there is reasonable assurance of compliance with the conditions of certification. If it is determined that reasonable assurance has not been provided, the licensee shall be notified with particularity and possible corrective measures suggested. Failure to notify the licensee in writing within ninety (90) days of receipt of a complete post-certification submittal shall constitute a determination of reasonable assurance of compliance.

V. CONSTRUCTION

A. Standards and Review of Plans

1. All construction at the facility shall be pursuant to the design standards presented in the application or amended application and the standards or plans and drawings submitted and signed by an engineer registered in the state of Florida. The site plan layout for Unit 5 shall be consistent with or have wetland impacts less than the plan attached hereto as Exhibit A. Any subsequent revisions to the site plan shall avoid and minimize wetland impacts at least to the same extent as is accomplished in Exhibit A. Specific DEP Southeast District Office acceptance of plans will be required based upon a determination of consistency with approved design concepts, regulations, and these conditions prior to initiation of construction of any: industrial waste treatment facility; domestic waste treatment facility; potable water treatment and supply system; ground water monitoring system, storm water runoff system; solid waste disposal area; and hazardous or toxic handling facility or area. The Licensee shall present specific plans for these facilities for review by the DEP Southeast District Office at least ninety (90) days prior to construction of those portions of the facility for which the plans are then being submitted, unless other time limits are specified in the following conditions herein. Review and approval or disapproval shall be accomplished in accordance with Chapter 120, F.S., or these Conditions of Certification as applicable.

2. The Department must be notified in writing and prior written approval obtained for any material change or revision to be made to the project during construction which is in conflict with these Conditions of Certification. If there is any material change or revision made to a project approved by the Department without this prior written approval, the project will be considered to have been constructed without Departmental approval, the construction will not be cleared for service, and the construction will be considered a violation of these Conditions of Certification.

3. Ninety (90) days prior to the anticipated date of first operation, the Licensee shall provide the Department with an itemized list of any changes made to the facility design and operation plans that would affect a change in discharge, as referenced in Condition

IV.C., subsequent to the time of issuance of this Certification. This pre-operational review of the final design and operation shall demonstrate continued compliance with Department rules and standards.

4. Final drainage plans illustrating any new or modified stormwater treatment facilities and conveyances for construction phases of the certified facility site shall be submitted to the DEP Southeast District Manager and the SFWMD as applicable for review and approval prior to construction of any such conveyance or facility. The Department shall indicate its approval or disapproval within 60 days of the submittal. Analysis report of the produced ground samples shall be submitted 30 days before surface water discharge begins.

B. Control Measures

1. To control runoff which may reach and thereby pollute waters of the state, necessary measures shall be utilized to settle, filter, treat or absorb silt containing or pollutant laden storm water to ensure against spillage or discharge of excavated material that may cause turbidity in excess of 29 Nephelometric Turbidity Units (NTU) above background in waters of the state or significant degradation of Outstanding Florida Waters in violation of Rule 62-4.242, F.A.C. Control measures may consist of sediment traps, barriers, berms, and vegetation plantings. Exposed or disturbed soil shall be protected and stabilized as soon as possible to minimize silt and sediment-laden runoff. The pH of the runoff shall be kept within the range of 6.0 to 8.5. The Licensee shall comply with the applicable nonprocedural requirements in Rules 40B-4, 40C-42, 40D-4 and/or 40E-4, F.A.C.

2. Any open burning in connection with initial land clearing shall be in accordance with Chapter 62-256, F.A.C., Chapter 5I-2, F.A.C., Uniform Fire Code Section 33.101, Addendum, and any other applicable county regulation. Any burning of construction-generated material, after initial land clearing that is allowed to be burned in accordance with Chapter 62-256, F.A.C., shall be approved by the DEP Southeast District office in conjunction with the Division of Forestry and any other county regulations that may apply. Burning shall not occur if not approved by the appropriate agency or if the Department or the Division of Forestry has issued a ban on burning due to fire safety conditions or due to air pollution conditions.

3. Disposal of sanitary wastes from construction toilet facilities shall be in accordance with applicable regulations of the appropriate local health agency.

4. Solid wastes resulting from construction shall be disposed of in accordance with the applicable regulations of Chapter 62-701, F.A.C.

5. The Licensee shall employ proper odor and dust control techniques to minimize odor and fugitive dust emissions. The applicant shall employ control techniques sufficient to prevent nuisance conditions which interfere with enjoyment of residents of adjoining property.

6. The Licensee shall develop the site so as to retain the buffer of natural vegetation as described in the Unit 5 application and in Condition IV.Q., Screening.

7. Dewatering operations during construction shall be carried out in accordance with Rule 62-621.300(2), F.A.C.

C. Environmental Control Program

An environmental control program shall be established under the supervision of a Florida registered professional engineer or other qualified person to assure that all construction activities conform to applicable environmental regulations and the applicable Conditions of Certification. If a violation of standards, harmful effects or irreversible environmental damage not anticipated by the application or the evidence presented at the certification hearing is detected during construction, the Licensee shall notify the DEP District Office as required by Condition IV.D., Compliance.

D. Reporting

Notice of commencement of construction shall be submitted to the Siting Coordination Office and the DEP Southeast District Office within fifteen (15) days after initiation. Starting three (3) months after construction commences, a quarterly construction status report shall be submitted to the DEP Southeast District Office. The report shall be a short narrative describing the progress of construction.

VI. UNIT 5 SPECIFIC CONDITIONS

A. Air

1. The construction and operation of the Turkey Point Unit 5 project shall be in accordance with all applicable provisions of Title V Air Operation Permit No. 0250003-11-AV, and Permit No.PSD-FL-338 (DEP Permit No. 0250003-006-AC), (attached as Appendices A and B) as well as any other permit required under a federal program such as Title III, Title IV and/or Title V issued for Turkey Point Unit 5 and any revisions, amendments, corrections or modifications thereto, and of Chapters 62-210 through 62-297, F.A.C.

2. All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Compliance Authority at:

Air Quality Division
DEP Southeast District Office
3301 Gun Club Road, MSC 7210-1
West Palm Beach, Florida 33406

Copies of all such documents shall also be submitted to Miami-Dade County at:

Air Quality Management
Department of Environmental Resources Management
33 Southwest 2nd Avenue, Suite 900
Miami, Florida 33130-1540

All documents related to applications for permits to construct, operate or modify an emissions unit shall be submitted to:

Division of Air Resource Management
Florida Department of Environmental Protection
2600 Blair Stone Road (MS #5505)

Tallahassee, Florida 32399-2400

and notice of all applications for permits to construct, operate or modify an emissions unit shall be submitted to:

Siting Coordination Office
Florida Department of Environmental Protection
2600 Blair Stone Road (MS #5500)
Tallahassee, Florida 32399-2400

B. Wetlands

1. Mitigation – Mitigation shall include on-site restoration and enhancement, purchase of credits in a mitigation bank, and contribution of wetlands for conservation purposes, as described in the document “Turkey Point Expansion Project, Refined Mitigation Proposal, FPL, April 2004” or as subsequently amended or modified.

a. Initial mitigation, by planting wetland plant species and hydrologic improvements, shall occur within 30 days of completion of construction; at this time the Licensee shall submit to the Department a baseline ("time zero") report. The report shall include details on the progress of the hydrologic improvements, a list of species planted, the number of individuals planted, and the date of the plantings. The report shall contain photographs, taken from referenced locations, to represent the entire site. Additionally, a drawing shall be included to show the location and direction of the camera. Subsequent monitoring reports shall be submitted quarterly, the first report being due 90 days after the baseline report. The quarterly reports shall include the number of plants surviving from the initial planting, additional seedlings planted, and explanations if survivorship is trending toward failure. The reports shall include photographs from the locations referenced in the baseline report.

b. Mitigation will be deemed successful when all of the following criteria have been continuously met on the mitigation site for a period of at least two growing seasons (but no earlier than two years after the initial planting), without intervention in the form of irrigation, dewatering, removal of undesirable vegetation, or replanting of desirable vegetation:

i. The percent cover of the mitigation wetland area exceeds 80% of native wetland plants

ii. Nuisance and exotic species are limited to 5% or less of the total cover.

iii. The desirable plants are reproducing naturally, either by normal, healthy vegetative spread, or through seedling establishment, growth and survival.

iv. The size distribution of the desirable species increases with time.

v. The functional assessment scores indicate that the functional value of the wetlands have made up for the functional loss of the project’s impacts.

c. The Licensee shall notify the SED whenever the Licensee believes the mitigation is successful, but in no event earlier than two years after the mitigation is implemented.

i. The notice shall include a copy of the most recent Annual Progress and Mitigation Success Report and a narrative that describes how the reported data support the claim that each of the mitigation success criteria has been met. The Licensee shall allow SED personnel the opportunity to schedule and conduct an on-site inspection of the mitigation site.

ii. Within 60 days of receipt of the notice, the SED shall notify the Licensee by certified mail that:

(1) That the mitigation has been successfully completed, or

(2) That the mitigation is not successful, identifying specifically those elements of the mitigation that do not meet the success criteria, or

(3) That the mitigation cannot be determined to be successful at this time, identifying specifically those elements of the mitigation that prevent the SED from determining whether the mitigation is successful.

iii. When the SED notifies the Licensee that the mitigation is successful, or, if the SED fails to notify the Licensee within the time period prescribed by this condition, then the Licensee's mitigation obligation under the terms of this certification shall be deemed satisfied.

d. The Licensee shall prepare a revised mitigation plan if, three (3) years after completion of planting, it is determined by the SED or the Licensee that the mitigation site will not meet the success criteria. The revised plan shall be submitted to the SED for review and approval and shall include the following:

i. The plan shall discuss why the mitigation site is not meeting the success criteria and propose a plan of action by which to correct any deficiencies in the original plan.

ii. The Licensee shall propose a schedule for implementation and completion of the provisions of the revised mitigation plan. Upon approval by the SED, the Licensee shall begin implementing the revised plan within 60 days of SED approval. The approved revised plan shall be copied to the Siting Coordination Office and shall be made a part of these Conditions of Certification.

2. Narrative progress reports shall be submitted every 6 months indicating the status of the mitigation efforts. The cover page shall indicate the certification number, project name and the Licensee name. The first semi-annual progress report shall be submitted six months after the date of certification issuance. Reports shall be submitted every six (6) months thereafter until all mitigation work required by these conditions of certification has been completed. The reports shall include the following information:

a. The date activities were begun. Indicate whether work has begun on-site.

b. A brief description of the extent of work (i.e., dredge, fill, monitoring, mitigation, management, maintenance) completed since the previous report or since this certification was issued. Show on copies of the site drawings those areas where work has been completed.

c. A brief description and the extent of work (i.e. dredge, fill, monitoring, mitigation, management, maintenance) anticipated to be accomplished within the next six months. Indicate on copies of the site drawings those areas where it is anticipated that work will be done.

d. The reports shall include photographs taken from the permanent stations, some of which must be in the vegetation sampling areas, a description of problems encountered and solutions undertaken, and anticipated work for the next six months.

e. The reports shall include, on the first page and just below the title, a signed certification by the individual who supervised preparation of the report the following statement: “This report represents a true and accurate description of the activities conducted during the six month period covered by this report.”

3. Best management practices for erosion control shall be implemented and maintained at all times during construction to prevent siltation and turbid discharges in excess of State water quality standards pursuant to Rule 62-302, F.A.C., or in excess of the ambient turbidity levels of Outstanding Florida Waters. Methods shall include, but are not limited to the use of staked hay bales, staked filter cloth, sodding, seeding, and mulching; staged construction; and the installation of turbidity screens around the immediate project site.

4. The Licensee shall be responsible for ensuring that erosion control devices/procedures are inspected and maintained daily during all phases of construction authorized by these Conditions of Certification until all areas that were disturbed during construction are sufficiently stabilized to prevent erosion, siltation, and turbid discharges.

5. The following measures shall be taken immediately by the Licensee whenever turbidity levels within waters of the State surrounding the project site exceed 29 NTUs above background or exceed the ambient water quality levels of Outstanding Florida Waters:

a. Immediately cease all work contributing to the water quality violation. Operations may not resume until the SED gives authorization to do so.

b. Notify the SED Environmental Resource Compliance/Enforcement Section at 561/681-6643 within 24 hours of the time the violation is first detected.

c. Stabilize all exposed soils contributing to the violation. Modify the work procedures that were responsible for the violation, install additional turbidity containment devices and repair any non-functioning turbidity containment devices.

6. The Licensee shall be responsible for ensuring that the construction and operation of the Project results in no significant degradation of the adjacent Biscayne National Park, an Outstanding Florida Water, in violation of Rule 62-4.242 and 62-302, F.A.C.

C. Domestic and Industrial Waste

The Licensee is hereby authorized to operate water and wastewater facilities as shown or described in the Turkey Point Unit 5 Site Certification Application and other documents on file with the Department and made a part hereof. The Licensee shall give the Department written notice at least 60 days before inactivation or abandonment of a wastewater facility and shall specify what steps will be taken to safeguard public health and safety during and following inactivation or abandonment.

D. Stormwater

1. Prior to construction, the Licensee shall submit a revised analysis to demonstrate that:

a. The post-development peak discharge rate does not exceed the pre-development discharge rate for the 25-year, 72-hour design storm, and

b. That the volume of the water quality treatment facility for off-site discharges is adequate to handle the post-development peak flow.

2. Final drainage plans illustrating all stormwater treatment facilities and conveyances for construction phase and for the operational phase of the Unit 5 site shall be submitted to the SED for review and approval prior to construction of any such conveyance or facility. The SED shall indicate its approval or disapproval within 60 days of the submittal or the submittal shall be considered approved.

3. Site construction activities shall be conducted in a manner which does not cause violations of state water quality standards. The Licensee shall implement best management practices for erosion and pollution control to prevent violation of state water quality standards. Temporary erosion control measures shall be implemented prior to any construction, and installation of permanent control measures shall be completed within seven (7) days of the start of any construction activity.

4. Turbidity barriers shall be installed and maintained at all locations where the possibility of transferring suspended solids into a receiving water body exists. Turbidity barriers shall remain in place at all locations until construction is completed, soils are stabilized, and vegetation has been established. The Licensee shall correct any erosion or shoaling that causes adverse impacts to water resources.

5. All construction at the facility shall be pursuant to the design standards presented in the application or amended application and the standards or plans and drawings submitted and signed by an engineer registered in the state of Florida. Specific SED acceptance of plans will be required based upon a determination of consistency with approved design concepts, regulations, and these conditions prior to initiation of construction of the stormwater management system Review and approval or disapproval shall be accomplished in accordance with Chapter 120, F.S., or these conditions of certification as applicable.

6. Within 30 days after completion of construction of the Stormwater management system, the Licensee shall submit a written statement of completion and certification by a registered professional engineer or other appropriate individual as authorized by law, utilizing the required "Environmental Resource Permit As-Built Certification" (DEP

Form No. 62-330.310(1), F.A.C.). The statement of completion and certification shall be based on on-site observation of construction or review of as-built drawings for the purpose of determining if the work was completed in compliance with permitted plans and specifications. This submittal shall serve to notify the Department that the system is ready for inspection. Additionally, if deviation from the approved drawings is discovered during the certification process, the certification must be accompanied by a copy of the approved permit drawings with deviations noted. Both the original and revised specifications must be clearly shown. The plans must be clearly labeled as "as-built" or "record" drawing. All surveyed dimensions and elevations shall be certified by a registered surveyor.

E. Solid and Hazardous Waste

No solid or hazardous waste is to be permanently stored onsite. Any hazardous waste generated on site shall be contained and transferred for disposal to a properly licensed contractor in accordance with the Department’s rules and regulations.

VII. UNIT 3 & 4 SPECIFIC CONDITIONS

A. Air

The operation of the Turkey Point Unit 3 and 4 Nuclear Plant shall be in accordance with all applicable provisions of Title V Air Operation Permit 0250003-010-AV. Title V Air Operation Permit 0250003-010-AV is incorporated by reference herein as part of this Certification and attached as Appendix C.

The provisions of the above shall be conditions of this certification. The licensee shall comply with the substantive provisions and limitations set forth in Title V Air Operation Permit Number 0250003-010-AV as part of these Conditions of Certification, and as those provisions may be modified, amended, or renewed in the future by the Department. Such provisions shall be fully enforceable as conditions of this certification. Any violation of such provisions shall be a violation of these Conditions of Certification.

B. Radiological

1. Decommissioning

Upon application to the U.S. Nuclear Regulatory Commission (NRC) for authority to decommission the plant, the applicant shall provide the Department a copy of the plan submitted to NRC for radioactive materials removal and/or containment for the site. Should the Department's review of the written plan reveal deficiencies, the Department shall bring such deficiencies to the attention of the applicant and the NRC and maintains the right to initiate a request, consistent with NRC procedural requirements that remedial action be taken to correct the deficiencies.

2. Emergency Plan

The applicant shall work with the State Division of Emergency Management and the State Department of Health, Bureau of Radiation Control, and Miami-Dade County in biennial updating of the emergency procedures and evacuation planning as necessary, including but not limited to improvements in communication and warning systems and in updating predicted plume overlays.

3. Radiological Release Limitations

The recommendation in the Power Plant Site Certification Analysis that certification be issued is based in part upon the fact that in order to obtain a construction permit and operating license from NRC, the applicant must comply with all applicable regulations, requirements, and standards of the NRC which limit the release of radioactive materials in solid waste, liquid or gaseous effluents to the environment. The above NRC regulations, requirements and standards include the following:

a. Standards for Protection Against Radiation, U.S. Nuclear Regulatory Commission Rules and Regulations, Title 10, Chapter 1, Part 20, Code of Federal Regulations, as presently in effect or hereafter amended.

b. Limitations and conditions for the controlled release of radioactive materials in solid, liquid and gaseous effluents contained in the Radiological Environmental Monitoring Program required by Title 10, 10 CFR 50, Appendix I as presently in effect or hereafter amended.

The Department has the statutory duty to insure that the location and operation of Turkey Point 3 and 4 will produce minimal adverse effects on human health, the environment, the ecology and the land and its wildlife, and the ecology of State waters and their aquatic life. (Fla. Stat. Section 403.502.) The Department has determined that the construction and operation of Turkey Point 3 and 4 must comply with the above radiological release limitations in order to minimize adverse effects on human health and the environment. This certification is conditioned upon full compliance by the applicant with the applicable above regulations, requirements and standards.

The NRC has the duty and responsibility imposed by statute, to enforce compliance by the applicant with NRC standards and technical specifications, to assure that the construction and operation of Turkey Point 3 and 4 will be in accord with the common defense and security and will provide adequate protection to the health and safety of the public. See Section 103(d) of the Atomic Energy Act, 42 U.S.C. section 2133(d) (1970); accord. 42 U.S.C. section 2332(a) (1970) including any revisions.

However, should the Department determine that the NRC has failed to discharge its duty and responsibility, it may bring any such deficiencies to the attention of the applicant and the NRC, and maintains the right to initiate a request, consistent with NRC procedural requirements, that appropriate enforcement action be taken to correct the deficiencies. Should such appropriate enforcement action not be forthcoming, and the Department determines that such enforcement action is necessary to insure that adverse effects on human health and the environment by continued operation of Turkey Point 3 and 4 are minimized, the Department reserves the right to take appropriate State enforcement action pursuant to Chapter 403, Florida Statutes, against the applicant for violation of any of the above radiological release limitations on the grounds that the violation of such limitations constitutes a violation of this express condition of certification.

4. Monitoring

The applicant shall comply with the most recent Department of Health Environmental Surveillance Agreement or its equivalent or future replacement. Should the

Department of Health determine that additional monitoring is required, it may take appropriate action to require such monitoring by modification of this condition of certification.

5. Interagency Agreement

The applicant shall comply with the Emergency Response Capability Agreement between the Florida Department of Health and the Florida Power and Light Company effective July 1, 1982, or as may be subsequently revised. (Attached as Exhibit B.)

6. Reservation of Legal Rights

The Department recognizes that the NRC has exclusive authority in certain areas related to the construction and operation of Turkey Point Units 3 and 4. These conditions of certification do not limit, expand or supersede any federal requirement or restriction under federal law, regulation, or regulatory approval or license. Compliance with the conditions herein does not constitute a waiver of the applicant's responsibility to comply with all applicable NRC requirements. Applicant's acceptance of these radiological conditions of certification does not, in and of itself, constitute a waiver by Applicant of any claim that any such radiological conditions are invalid under the doctrine of federal preemption or otherwise by law.

7. Annual Radiological Environmental Operating Report

Upon submittal to the NRC, a copy of the Annual Radiological Environmental Operating Report for Turkey Point Units 3 & 4 shall be provided to the Department's Siting Coordination Office.

VIII. INDUSTRIAL WASTE DISCHARGES

Any discharges during construction and operation of Units 3, 4 & 5 shall be in accordance with all applicable provisions of NPDES permit No. FL0001562-004-IW1N (attached as Appendix D) as well as any subsequent modifications, amendments and/or renewals.

IX. BISCAYNE BAY SURFACE WATER MONITORING

As proposed, the Turkey Point Units 3 and 4 uprate project may cause an increase in temperature and salinity in the cooling canal system. Field data is needed in order to determine impacts of the proposed changes in the Turkey Point cooling canal system on Biscayne Bay.

A. No later than July 31, 2009, FPL shall submit a Biscayne Bay Surface Water Monitoring Plan (Plan) pursuant to Chapter 62-302, F.A.C. to the DEP Southeast District Office for review and approval. The submittal deadline may be extended upon agreement between the Licensee, DEP, SFWMD and Miami-Dade County. Agreements for extensions shall be submitted to the Siting Office prior to the deadline. The Plan shall include, at a minimum, the following components:

1. salinity and temperature monitoring within the surface waters of the Bay, including the Biscayne Bay Aquatic Preserve; (Specific parameters to be measured, including specific conductance and temperature, shall be sampled in accordance with Chapter 62-160, F.A.C.);

2. a minimum of five monitoring stations located near shore in the vicinity of the Turkey Point Plant; and

3. specific monitoring locations, sampling frequencies and methods, and specific parameters to be monitored.

B. This monitoring data shall be compared to data using compatible monitoring instrumentation already in place in Biscayne Bay.

C. FPL shall continue the monitoring of salinity and temperature in the cooling canals under its industrial waste water facility permit.

D. If the Department determines that the pre- and post-Uprate salinity and temperature monitoring data indicate potential adverse changes in the surface water in Biscayne Bay, then the Department may propose additional measures to evaluate or to abate such impacts to Biscayne Bay.

E. The Plan, including monitoring locations, shall be approved prior to implementation. The Department shall indicate its approval or disapproval of the submitted plan within 90 days of the originally submitted information. In the event that the Department requires additional information for the licensee to complete, and the Department to approve the Plan, the Department shall make a written request to the licensee for additional information no later than 30 days after receipt of the submitted information. Any changes to the approved Surface Water Monitoring Plan shall be approved by Coastal and Aquatic Managed Areas personnel in consultation with other FDEP personnel.

[62-160, 62-302, 62-302.700, 62-520.600, F.A.C.]

X. SURFACE WATER, GROUND WATER, ECOLOGICAL MONITORING

This is a consolidated condition agreed upon by three agencies, Department of Environmental Protection (DEP), Miami-Dade County Department of Environmental Resource Management (DERM) and the South Florida Water Management District (SFWMD). This consolidated condition sets forth the framework for new monitoring and, as may be needed, abatement or mitigation measures, for approval of FPL’s Turkey Point Units 3 and 4 Uprate Application. Specific monitoring and potential modeling parameters will be identified and implemented pursuant to a monitoring plan as part of a supplemental agreement between FPL and the SFWMD as described below.

A. In addition to the monitoring framework set forth in this consolidated condition, no later than July 31, 2009, FPL shall execute a SFWMD approved Fifth Supplemental Turkey Point Agreement ("Fifth Supplemental Agreement") to the original 1972 Agreement between FPL and the SFWMD pertaining to FPL's obligation to monitor for impacts of the Turkey Point cooling canal system on the water resources of the SFWMD in general and the facilities and operations of the SFWMD (the "Agreement"). Subject to the SFWMD's approval, FPL shall also amend the Agreement's Revised Operating Manual as referenced in paragraph C. "Monitoring Provisions" (the "Revised Plan") of the Fourth Supplemental Agreement, dated July 15, 1983. The Revised Plan shall be incorporated into the Fifth Supplemental Agreement and shall include assessment of potential impacts to surface water and ground water including wetlands, as needed, in the vicinity of the cooling canal system. The specific monitoring boundaries shall be determined as part of the Revised Plan. The submittal deadline may be extended upon agreement between the Licensee, the SFWMD, DEP and Miami-Dade County. Agreements for extensions shall be submitted to the Siting Office prior to the deadline.

B. The Revised Plan shall be designed to be in concurrence with other existing and ongoing monitoring efforts in the area and shall include but not necessarily be limited to, surface water, groundwater and water quality monitoring, and ecological monitoring to:

1. delineate the vertical and horizontal extent of the hyper-saline plume that originates from the cooling canal system and to characterize the water quality including salinity and temperature impacts of this plume for the baseline condition;

2. determine the extent and effect of the groundwater plume on surface water quality as a baseline condition; and

3. detect changes in the quantity and quality of surface and ground water over time due to the cooling canal system associated with the Uprate project. The Revised Plan shall include installation and monitoring of an appropriate network of wells and surface water stations. The Revised Plan shall be approved by the SFWMD in consultation with the DEP Office of Coastal and Aquatic Managed Areas, the DEP Southeast District Office and DERM.

C. FPL shall transmit electronic copies of all data and reports required under the Fifth Supplemental Agreement and the Revised Plan in accordance with timeframes as approved in the Fifth Supplemental Agreement to:

SFWMD, Director, Water Supply (or alternative transmittal procedures to be described in the Fifth Supplemental Agreement);

Miami-Dade County, Director, DERM;

DEP, Director, Southeast District Office;

DEP Siting Coordination Office

DEP, Director, Biscayne Bay Aquatic Preserve Manager,

D. If the DEP in consultation with SFWMD and DERM determines that the pre- and post-Uprate monitoring data: is insufficient to evaluate changes as a result of this project; indicates harm or potential harm to the waters of the State including ecological resources; exceeds State or County water quality standards; or is inconsistent with the goals and objectives of the CERP Biscayne Bay Coastal Wetlands Project, then additional measures, including enhanced monitoring and/or modeling, shall be required to evaluate or to abate such impacts. Additional measures include but are not limited to:

1. the development and application of a 3-dimensional coupled surface and groundwater model (density dependent) to further assess impacts of the Uprate Project on ground and surface waters; such model shall be calibrated and verified using the data collection during the monitoring period;

2. mitigation measures to offset such impacts of the Uprate Project necessary to comply with State and local water quality standards, which may include methods and features to reduce and mitigate salinity increases in groundwater including the use of highly treated reuse water for recharge of the Biscayne Aquifer or wetlands rehydration;

3. operational changes in the cooling canal system to reduce any such impacts; and/or

4. other measures to abate impacts as may be described in the Revised Plan.

[Sections 373.016, 373.223, F.S.; Rules 40E-4.011, 40E-4.301, 40E-4.302, F.A.C.; Sections 62-302 and 62-520, F.A.C.; Section 24-42, Code of Miami-Dade County, Miami-Dade County Comprehensive Development Master Plan (CDMP) Land Use Element, Conservation Element, Intergovernmental Coordination Element, Coastal Management Element.]

XI. COOLING CANAL SYSTEM FLORIDAN PRODUCTION WELL MONITORING

FPL shall monitor the proposed Floridan production wells (F-1, F-2, F-3, F-4 and F-5) on a quarterly basis for: water level or pressure; temperature; pH, Total Dissolved Solids; specific conductance; major anions/cations (including chlorides); NH3; total nitrogen; and total phosphorus. This monitoring data shall be made available to Miami-Dade County as well as FDEP and the SFWMD. On a semi-annual basis, Miami-Dade County may collect groundwater samples of the proposed Floridan production wells (F-1, F-2, F-3, F-4 and F-5) for constituents including but not limited to O18/16 and Strontium (87Sr/86Sr).

[Pre-Hearing Joint Stipulation signed 11/20/15 and Final Order issued by the Siting Board signed 4/1/16]

XII. COOLING CANAL SYSTEM

Permits and approvals that regulate the operation of the cooling canal system are incorporated herein and attached as Appendices. These permits and approvals shall be fully enforceable by both the permitting agency and as Conditions of Certification for Units 3 and 4. Any violation of such permits and approvals, where it is determined that Units 3 and 4 are the cause, shall also be a violation of these Conditions of Certification.

XIII. WATER MANAGEMENT DISTRICT

A. General

1. If this Certification is transferred, pursuant to Condition IV.O., from the Licensee to another party, the Licensee from whom the Certification is transferred shall remain liable for corrective actions that may be required as a result of any violations that occurred prior to the transfer.

2. This Certification is based in part on the Licensee's submitted information to the SFWMD which reasonably demonstrates that harm to the site water resources will not be caused by the authorized activities. The plans, drawings and design specifications submitted by the Licensee shall be considered the minimum standards for compliance with conditions XI.

3. This project must be constructed, operated and maintained in compliance with and meet all non-procedural requirements set forth in Chapter 373, F.S., and Chapters 40E-2 (Consumptive Use), and 40E-3 (Water Wells), F.A.C.

4. It is the responsibility of the Licensee to ensure that harm to the water resources does not occur during the construction, operation, and maintenance of the project.

5. The Licensee shall hold and save the SFWMD harmless from any and all damages, claims, or liabilities which may arise by reason of the construction, alteration, operation, maintenance, removal, abandonment and/or use of any system authorized by this Certification, to the extent allowed under Florida law.

6. The Licensee shall be responsible for the construction, operation, and maintenance of all facilities installed for the proposed project.

7. SFWMD representatives shall be allowed reasonable escorted access to the power plant site, the water withdrawal facilities and any associated facilities to inspect and observe any activities associated with the construction of the proposed project and/or the operation and/or maintenance of the on-site wells in order to determine compliance with these Conditions of Certification. The Licensee shall not refuse entry or access to any SFWMD representative who, upon reasonable notice, requests entry for the purpose of the above noted inspection and presents appropriate credentials.

8. Information submitted to the SFWMD subsequent to Certification, in compliance with these Conditions of Certification, shall be for the purpose of the SFWMD determining the Licensee's compliance with conditions XIII and the non-procedural criteria contained in Chapters 40E-2 and 40E-3, F.A.C., as applicable, prior to the commencement of the subject construction, operation and/or maintenance activity covered by this Certification.

9. The SFWMD may take any and all lawful actions that are necessary to enforce any condition of this Certification based on the authorizing statutes and rules of the SFWMD. Prior to initiating such action, the SFWMD shall notify the Siting Coordination Office of DEP of the proposed action.

10. At least ninety (90) days prior to the commencement of construction of any portion of the project, the Licensee shall submit to SFWMD staff, for a completeness and sufficiency review, any pertinent additional information required under conditions XIII for that portion of project. If SFWMD staff does not issue a written request for additional information within thirty (30) days, the information shall be presumed to be complete and sufficient.

11. Within sixty (60) days of the determination by SFWMD staff that any additional information is complete and sufficient, the SFWMD shall determine and notify the Licensee in writing whether the proposed activities conform to SFWMD rules, as required by Chapters 40E-2 and 40E-3, F.A.C., and these Conditions of Certification. If the information is not complete or sufficient, the SFWMD shall identify what items remain to be addressed. No construction activities shall begin until the SFWMD has notified the Licensee in writing that the activities are in compliance with the applicable SFWMD criteria, or failed to notify the Licensee in writing within sixty (60) days of finding the information to be complete and sufficient.

12. The Licensee shall submit any proposed revisions to the site specific design authorizations specified in this Certification to the SFWMD for review and approval prior to implementation. The submittal shall include all the information necessary to support the proposed request, including detailed drawings, calculations and/or any other applicable data. Such requests may be included as part of an appropriate additional information submittal

required by this Certification provided they are clearly identified as a requested amendment or modification to the previously authorized design

B. Water Use Authorizations

1. In the event of a declared water shortage, the Licensee must comply with any water withdrawal reductions ordered by the SFWMD in accordance with the Water Shortage Plan, Chapter 40E-21, F.A.C.

2. The Licensee shall mitigate interference with existing legal uses that were caused in whole or in part by the Licensee's withdrawals, consistent with the approved mitigation plan. As necessary to offset the interference, mitigation will include pumpage reduction, replacement of the impacted individual's equipment, relocation of wells, change in withdrawal source, or other means. Interference to an existing legal use is defined as an impact that occurs under hydrologic conditions equal to or less severe than a 1 in 10 year drought event that results in the:

a. Inability to draw water consistent with provisions of the permit, such as when remedial structural or operational actions not materially authorized by existing permits must be taken to address the interference; or

b. Change in the quality of water pursuant to primary State Drinking Water Standards to the extent that the water can no longer be used for its authorized purpose, or such change is imminent.

c. The inability of an existing legal user to meet its permitted demands without exceeding the permitted allocation.

3. The Licensee shall mitigate harm to existing off-site land uses caused by the Licensee's withdrawals, as determined through reference to the conditions for permit issuance. When harm occurs, or is imminent, the SFWMD will require the Licensee to modify withdrawal rates or mitigate the harm. Harm, as determined through reference to these Conditions of Certification includes:

a. Significant reduction in water levels on the property to the extent that the designed function of the water body and related surface water management improvements are damaged, not including aesthetic values. The designed function of a water body is identified in the original permit or other government authorization issued for the construction of the water body. In cases where a permit was not required, the designed function shall be determined based on the purpose for the original construction of the water body (e.g., fill for construction, mining, drainage canal, etc.);

b. Damage to agriculture, including damage resulting from reduction in soil moisture resulting from consumptive use;

c. Land collapse or subsidence caused by reduction in water levels associated with consumptive use.

4. The Licensee shall mitigate harm to natural resources caused by the Licensee's withdrawals, as determined through reference to the conditions for permit issuance. When harm occurs, or is imminent, the SFWMD will require the Licensee to modify withdrawal

rates or mitigate the harm. Harm, as determined through reference to the conditions for permit issuance includes:

a. Reduction in ground or surface water levels that results in harmful lateral movement of the fresh water/salt water interface;

b. Reduction in water levels that harm the hydroperiod of wetlands;

d. Significant reduction in water levels or hydroperiod in a naturally occurring water body such as a lake or pond;

e. Harmful movement of contaminants in violation of state water quality standards; or

f. Harm to the natural system including damage to habitat for rare or endangered species.

5. At any time, if there is an indication that the well casing, valves, or controls associated with the on-site well system leak or have become inoperative, the Licensee shall be responsible for making the necessary repairs or replacement to restore the well system to an operating condition acceptable to the SFWMD. Failure to make such repairs shall be the cause for requiring that the well(s) be filled and abandoned in accordance with the procedures outlined in Chapter 40E-3, F.A.C.

C. Site Specific Design Authorizations

1. This Certification authorizes an average daily withdrawal of 28.06 million gallons per day (MGD) from the upper production zones of the Floridan aquifer. This allocation is further divided as follows:

14.06 MGD used for cooling water for Unit 5 and process water for Units 1, 2, 3, 4, and 5.

14.00 MGD for salinity reduction in the on-site cooling canal system (CCS).

2. Upon written notification from the SFWMD that a reliable source of reclaimed water is available at the project site to serve Unit 5 in a quantity and quality acceptable to the Licensee for cooling purposes for Unit 5, the Licensee shall provide the SFWMD with a schedule for use of reclaimed water, for the SFWMD's review and approval, within 90 days of such notification. Once the use of reclaimed water has been established, the use of Floridan Aquifer water shall be reduced in proportion to the volume of reclaimed water made available to Unit #5, such that the combined sources meet the total demand of a 90-day average withdrawal of 14.06 MGD and an average annual withdrawal of 4,599 MGY. Should reclaimed water become temporarily unavailable, the Licensee shall notify the SFWMD within 24 hours of commencing temporary withdrawals from the Floridan aquifer.

3. The Licensee is currently utilizing and authorized to construct the following wells:

Existing Floridan Aquifer Wells

ID	Casing Diameter (inches)	Cased Depth (feet)	Max Depth (feet)	Max Flow (gpm)

PW-1	24	1,003	1,242	5,000
PW-3	24	1,005	1,247	5,000
PW-4	24	1,015	1,243	5,000

Authorized (never constructed) Floridan Aquifer Wells – Unit 5 Cooling

ID	Casing Diameter (inches)	Cased Depth (feet)	Max Depth (feet)	Max Flow (gpm)
PW-2	24	1,020	1,400	5,000

Proposed Floridan Aquifer Well – CCS Salinity Reduction

ID	Casing Diameter (inches)	Cased Depth (feet)	Max Depth (feet)	Max Flow (gpm)
F-1	20	1,020	1,400	2,500
F-2	20	1,020	1,400	2,500
F-3	20	1,020	1,400	2,500
F-4	20	1,020	1,400	2,500
F-5	20	1,020	1,400	2,500
F-6	20	1,020	1,400	2,500

(Cased and Max Depths indicated for proposed wells are estimated based on existing information and may change as needed to accommodate natural changes in the subsurface.)

4. Prior to the use of any proposed withdrawal facilities authorized under this Certification, the Licensee shall equip each facility with a SFWMD-approved operating water use accounting system and submit a report of calibration to the SFWMD, pursuant to Section 4.1.1 of the Applicants Handbook For Water Use Permit Applications Within the SFWMD. In addition, the Licensee shall submit a report of recalibration for the water use accounting system for each water withdrawal facility (existing and proposed) authorized -under this Certification every five years from each previous calibration, continuing at five year increments. The Licensee shall report monthly withdrawals for each withdrawal facility to the SFWMD quarterly. The Licensee shall specify the water accounting method and means of calibration on each report.

5. Prior to operating the proposed Floridan aquifer wells for the CCS salinity reduction, the Licensee shall submit an operational plan showing how the water use will vary between the wet and dry seasons.

6. *Modifications*

a. Pursuant to Section 373.236(4), F.S., every ten years from the date of certification issuance, the Licensee shall submit a water use compliance report for review and approval by SFWMD staff to SFWMD at www.sfwmd.gov/ePermitting, or Regulatory Support, MSC 9611, P.O. Box 24680, West Palm Beach, FL 33416-4680.

b. The Licensee may request a modification of the groundwater withdrawals for consumptive use authorized by this Certification in accordance with the provisions of Section 403.516. F.S. and Section 62-17.211, F.A.C. Any request for an increase in water withdrawals shall be made pursuant to the provisions of Section 403.516, F.S., and Section 62-17.211, F.A.C.

7. Prior to the commencement of construction of those portions of the project which involve dewatering activities, the Licensee shall submit a detailed plan for the proposed dewatering activities to the SFWMD for a determination of compliance with the non-procedural requirements of Chapters 40E-2 and 40E-3, F.A.C., in effect at the time of submittal. The following information, referenced to NGVD where appropriate, shall be submitted:

a. A detailed site plan which shows the location(s) for each proposed dewatering area;

b. The method(s) used for each dewatering operation;

c. The maximum depth for each dewatering operation;

d. The location and specifications for all proposed wells and/or pumps associated with each dewatering operation;

e. The duration of each dewatering operation;

f. The discharge method, route, and location of receiving waters generated by each dewatering operation, including the measures (Best Management Practices) that will be taken to prevent water quality problems in the receiving water(s);

g. An analysis of the impacts of the proposed dewatering operations on any existing on and/or off-site legal users, wetlands, or existing groundwater contamination plumes;

h. The location of any infiltration trenches and/or recharge barriers; and

i. All plans must be signed and sealed by a Professional Engineer or a Professional Geologist registered in the State of Florida.

8. If, during the control of these conditions of certification, any on-site wells require repair, replacement, and/or abandonment, the Licensee shall submit the information described in Chapter 40E-3, F.A.C. for review by the SFWMD prior to initiating such activities.

9. Prior to construction of the proposed on-site wells, the Licensee shall submit the drilling plans and other pertinent information required by Chapter 40E-3, F.A.C. to the SFWMD for review and approval. If the final well locations are different from those originally proposed in the site certification application, the Licensee shall also submit to the SFWMD for review and approval an evaluation of the impacts of the proposed pumpage from the alternate well location(s) on adjacent existing legal users, pollution sources, environmental features, and water bodies.

10. *Groundwater Monitoring Plan*

a. Within three months of issuance of this Certification, a preliminary groundwater monitoring plan shall be submitted to the SFWMD for a determination of compliance with the non-procedural requirements of Chapter 40E-2, F.A.C. In developing the monitoring plan, the Licensee shall consider well locations, depth and method of construction, types of screens, and frequency of data collection.

b. Within six months of issuance of this Certification, the Licensee shall implement the groundwater monitoring plan.

c. Data from the monitoring described in Section X of these Conditions of Certification shall be used to evaluate the effectiveness of the CCS salinity reduction in both the CCS and the underlying Biscayne aquifer. In addition, monthly sampling for chloride concentration from the Floridan aquifer production wells used to reduce the salinity reduction in the CCS is required.

11. *Water Conservation Plan*

a. Prior to the commencement of construction, the Licensee shall submit a water conservation plan, as described in Chapter 40E-2, F.A.C., for review and approval by SFWMD staff.

b. The water conservation plan shall incorporate the following components:

i. An audit of the amount of water needed in the Licensee’s operational processes. The following measures shall be implemented within one year of audit completion if found to be cost effective in the audit:

(1) Implementation of a leak detection and repair program;

(2) Implementation of a recovery/recycling or other program providing for technological, procedural or programmatic improvements to the Licensee’s facilities; and

(3) Use of processes to decrease water consumption.

ii. Development and implementation of an employee awareness program concerning water conservation.

XIV. DEPARTMENT OF TRANSPORTATION

A. Access Management to the State Highway System:

Any access to the State Highway System will be subject to the requirements of Rule Chapters 14-96, State Highway System Connection Permits, and 14-97, Access Management Classification System and Standards, Florida Administrative Code.

B. Overweight or Overdimensional Loads:

Operation of overweight or overdimensional loads by the applicant on State transportation facilities during construction and operation of the utility facility will be subject to safety and permitting requirements of Chapter 316, Florida Statutes, and Rule Chapter 14-26, Safety Regulations and Permit Fees for Overweight and Overdimensional Vehicles, Florida Administrative Code.

C. Use of State of Florida Right of Way or Transportation Facilities:

All usage and crossing of State of Florida right of way or transportation facilities will be subject to Rule Chapter 14-46, Utilities Installation or Adjustment, Florida Administrative Code; Florida Department of Transportation's Utility Accommodation Manual (Document 710-020-001); Design Standards for Design, Construction, Maintenance and Utility Operation on the State Highway System; Standard Specifications for Road and Bridge Construction; and pertinent sections of the Florida Department of Transportation's Project Development and Environmental Manual. U.S. 1 has been identified as Florida Intrastate Highway System (FIHS) and Strategic Intermodal System's (SIS) facilities.

D. Standards:

The Manual on Uniform Traffic Control Devices; Florida Department of Transportation's Design Standards for Design, Construction, Maintenance and Utility Operation on the State Highway System; Florida Department of Transportation's Standard Specifications for Road and Bridge Construction; Florida Department of Transportation's Utility Accommodation Manual; and pertinent sections of the Department of Transportation's Project Development and Environmental Manual will be adhered to in all circumstances involving the State Highway System and other transportation facilities.

E. Drainage:

Any drainage onto State of Florida right of way and transportation facilities will be subject to the requirements of Rule Chapter 14-86, Drainage Connections, Florida Administrative Code, including the attainment of any permit required thereby.

F. Use of Air Space:

Any newly proposed structure or alteration of an existing structure will be subject to the requirements of Chapter 333, F.S., and Rule 14-60.009, Airspace Protection, F.A.C. Additionally, notification to the Federal Aviation Administration (FAA) is required prior to beginning construction, if the structure exceeds notification requirements of 14 CFR Part 77, Objects Affecting Navigable Airspace, Subpart B, Notice of Construction or Alteration. Notification will be provided to FAA Southern Region Headquarters using FAA Form 7460-1, Notice of Proposed Construction or Alteration in accordance with instructions therein. A subsequent Determination by the FAA stating that the structure exceeds any federal obstruction standard of 14 CFR Part 77, Subpart C for any structure that is located within a 10-nautical-mile radius of the geographical center of a public-use airport or military airfield in Florida will be required to submit information for an Airspace Obstruction Permit from the Florida Department of Transportation or variance from local government depending on the entity with jurisdictional authority over the site of the proposed structure. The FAA Determination regarding the structure serves only as a review of its impact on federal airspace and is not an authorization to proceed with any construction. However, FAA recommendations for marking and/or lighting of the proposed structure are made mandatory by Florida law. For a site under Florida Department of Transportation jurisdiction, application will be made by submitting Florida Department

Transportation Form 725-040-11, Airspace Obstruction Permit Application, in accordance with the instructions therein.

G. Level of Service on State Roadway Facilities:

All traffic impacts to State roadway facilities on the FIHS or the SIS, or funded by Section 339.2819, Florida Statutes, will be subject to the requirements of the level of service standards adopted by local governments pursuant to Rule Chapter 14-94, Statewide Minimum Level of Service Standards, Florida Administrative Code, in accordance with Section 163.3180(10), Florida Statutes. All traffic impacts to State roadway facilities not on the FIHS, the SIS, or funded by Section 339.2819, Florida Statutes, will be subject to adequate level of service standards established by the local governments.

H. Best Management Practices

Traffic control during facility construction and maintenance will be subject to the standards contained in the Manual on Uniform Traffic Control Devices; Rule Chapter 14-94, Statewide Minimum Level of Service Standards, Florida Administrative Code; Florida Department of Transportation's Design Standards for Design, Construction, Maintenance and Utility Operation on the State Highway; Florida Department of Transportation's Standard Specifications for Road and Bridge Construction; and Florida Department of Transportation's Utility Accommodation Manual, whichever is more stringent.

It is recommended that the applicant encourage transportation demand management techniques by doing the following:

1. Placing a bulletin board on site for car pooling advertisements.
2. Requiring that heavy construction vehicles remain onsite for the duration of construction to the extent practicable.

If the applicant uses contractors for the delivery of any overweight or overdimensional loads to the site during construction, the applicant should ensure that its contractors adhere to the necessary standards and receive the necessary permits required under Chapter 316, Florida Statutes, and Rule Chapter 14-26, Safety Regulations and Permit Fees for Overweight and Overdimensional Vehicles, Florida Administrative Code.

I. Railroad Spur

Any newly proposed railroad crossing must comply with the criteria established in Rule Chapter 14-57, Florida Administrative Code (FAC). The following criteria must be considered in opening a new public highway-rail grade crossing on any state, county, or city roadway:

1. Safety
2. Necessity for rail and vehicle traffic.
3. Alternate routes.
4. Effect on rail operations and expenses.
5. Closure of one or more public railroad-grade crossings to offset opening a new crossing.

6. Design of the grade crossing and road approaches.

7. Presence of multiple tracks and their effect upon railroad and highway operations.

The installation of a new public highway-rail grade crossing must have as a minimum roadside flashing lights and gates on all roadway approaches to the crossing. The installation of the crossing surface and signals must be in accordance with current Manual of Uniform Traffic Control Devices (MUTCD), Federal Railroad Administration Rules and Regulations, American Association of State Highway and Transportation Officials (AASHTO) Policy, and the Department's Manual of Uniform Minimum Standards for Design, Construction, and Maintenance for Streets and Highways (Florida's Green Book).

Areas of concern to be considered in determining the rail crossing location are as follows:

1. Roads crossing the tracks at a skewed angle or where the track is curved or super-elevated;

2. Impaired sight distance for motorists and rail engineers;

3. Highway intersections within 75 feet of the crossing which create a greater potential for accidents and create minimal vehicle storage distance;

4. Crossings that are blocked for long periods of time;

5. Switching movements or turnouts;

6. Different elevations of tracks.

XV. EMERGENCY MANAGEMENT

A. FPL shall incorporate the Unit 5 site into the Comprehensive Hurricane Preparation and Recovery Plan for the overall Turkey Point Power Plant Site.

B. FPL shall submit a formal update of the Comprehensive Hurricane Preparation and Recovery Plan to the State Division of Emergency Management, the Miami-Dade County Office of Emergency Management every five (5) years following commencement of commercial operation of the Unit 5 and whenever an additional electrical generating unit is brought into service at the Turkey Point Plant site.

XVI. MIAMI-DADE COUNTY

A. General

Construction and operation of the certified facilities shall be in accordance with all applicable nonprocedural requirements of the laws and ordinances of Miami Dade County in effect on November 14, 2003, including, but not limited to, the Miami Dade Comprehensive Development Master Plan and Chapters 8, 11C, 14, 18A, 24, and 33 of the Code of Miami Dade County, Florida.

B. Unit 5 Expansion Project

1. Protection of Existing Legal Water Users

a. As provided in Condition XI.B.2., if SFWMD determines that the potential exists for Licensee's proposed Floridan Aquifer withdrawals to cause interference with existing legal users, authorization for such withdrawals shall be contingent upon SFWMD establishing acceptable withdrawal rates and requiring necessary and appropriate mitigation, pursuant to SFWMD's Basis of Review for Water Use Permits, to prevent interference with existing legal users. Licensee shall submit copies of any reports on additional modeling, alternative water supplies, and mitigation plans to WASD.

b. Licensee shall provide a copy to WASD of any notice received from SFWMD pursuant to Condition XI.C.3., that a reliable source of reclaimed water is available at the Project site to serve Unit 5.

c. If reclaimed water from the South District Wastewater Treatment Plant is used as a source of makeup to the Unit 5 cooling tower, blowdown from the cooling tower shall be returned to the South District Wastewater Treatment Plant for treatment and disposal. The requirements of Section 24-11(9) of the Code of Miami Dade County, as revised in March 2004, or as subsequently revised pursuant to federal or state law, shall apply to such blowdown returned to the South District Wastewater Treatment Plant.

2. The following detailed plans must be submitted to Miami Dade County Department of Environmental Resources Management (DERM) prior to initiation of work in tidal waters or wetlands:

a. The site plan layout shall be consistent with, or have wetland impacts less than, the plans described in the document "Turkey Point Expansion Project, Refined Mitigation Proposal, FPL, April 2004" or as subsequently amended or modified.

b. Two or more sets of construction drawings and engineering calculations signed and sealed by a professional engineer registered in the State of Florida and a land survey sealed by a licensed land surveyor registered in the State of Florida for those elements of the project that involve wetlands. These plans must include sufficient detail and be prepared at a scale that clearly identifies the limits of filling in wetlands and tidal waters, on-site mitigation areas, structures other than fill in tidal waters or wetlands, and typical cross-sections of all elements of the project that affect wetlands.

c. A construction management plan which shall include methods or best management practices for preventing or controlling secondary impacts from turbidity, siltation, fugitive dust, unpermitted impacts to adjoining waters or wetlands, fill or excavated material, construction debris, noise, or artificial lighting.

d. A plan for further assessment of materials proposed to be used for filling tidal water and wetlands, including physical, chemical and biological effects tests as determined in cooperation with local and state environmental agencies. Placement of fill shall not commence until additional testing and analysis of physical, chemical, and biological characteristics of fill material have been completed in accordance with requirements of DERM.

e. A water quality and biological monitoring plan for documenting compliance with narrative and numerical water quality targets during construction.

f. A post-construction long-term water quality and biological monitoring plan for areas near or downstream of the built areas, on-site mitigation areas, and on-site restoration areas.

g. A detailed on-site mitigation and restoration plan including signed and sealed construction drawings (plan views and cross-sections), planting configuration and species list, hydraulic or tidal exchange calculations, exotic control and maintenance methods, and success criteria. This plan shall be consistent with the document "Turkey Point Expansion Project, Refined Mitigation Proposal, FPL, April 2004" or as subsequently amended or modified.

h. A plan for monitoring and responding to the occurrence of endangered (or other listed species) in the construction area.

i. A stormwater management plan, including calculations and construction drawings.

j. A plan for training all on-site construction-related workers with respect to environmental resource protection requirements.

3. The applicant shall mark in a conspicuous fashion the boundaries or limits of all work/fill areas, mitigation areas, preservation areas, or protected species habitat. This may be accomplished with fencing, flagging, buoys, silt barriers, hay bales, or other forms of durable demarcation. Field markers shall include survey benchmarks or reference points that can be compared to approved construction plans and drawings. Prior to construction in wetlands or tidal waters, the layout must be approved by DERM. The markers shall be maintained for the entirety of construction to facilitate compliance inspections and also to reduce the chance of unauthorized impacts to resources.

4. Seven days prior to the start of construction in wetlands or tidal waters, the Licensee shall allow prior approved third party access for the salvage of desirable native vegetation occurring within the areas to be filled or cleared.

5. Dredging and filling of coastal wetlands shall be limited to the minimum amount for public necessity or enhancement of biological, chemical or physical characteristics of adjacent waters.

6. On-site mitigation and restoration areas shall be maintained free (less than 1% cover) of invasive exotic vegetation in perpetuity.

7. Within 90 days of the start of construction, the Licensee shall convey title of 307 acres of wetland, as defined in the "Turkey Point Expansion Project, Refined Mitigation Proposal, FPL, April 2004" or as subsequently amended or modified, to the appropriate federal, state, or local resource management agency for conservation or restoration purposes consistent with the goals of ongoing regional restoration plans.

8. Unconsolidated shorelines created as a result of the project shall be stabilized with native vegetation, such as but not limited to mangroves. If seawalls or bulkheads are constructed in or adjacent to tidal waters, they shall include the use of rip-rap or similar wave attenuation devices in their design.

9. Construction of on-site mitigation shall be initiated within 90 days of the beginning of filling of coastal wetlands or tidal waters. Construction of on-site mitigation shall be completed within 90 days of the completion of filling of wetlands except areas to be restored after completion of project construction.

10. Restoration of temporarily filled wetlands shall commence within 60 days of completion of construction on the power block or by January 2010, whichever first occurs.

11 Should upland construction damage or require removal of upland trees, the Licensee shall be required to preserve specimen trees (trunk > 18 in. DBH) and replace upland tree canopy in accordance with the requirements of Article III. Tree Preservation and Protection Sec. 24-60 of the Code of Miami-Dade County. This requirement includes trees along entrance roads and existing landscaped areas, and shall be in addition to establishment of coastal hammocks proposed as part of on-site mitigation.

12. Exotic pest plant species on the development site uplands shall be removed prior to development.

13. Temporary and permanent fill pads shall be graded to slope away from tidal waters and wetlands.

14. Construction of permanent parking areas, walkways, and amenities shall use semi-pervious materials to reduce runoff where feasible and compatible with safety requirements.

15. This Certification does not replace or eliminate the need for appropriate annual operating permits from Miami-Dade County for any existing, new or improved facilities located at the Turkey Point Power Plant site but not within the area covered by this Certification as delineated in the Site Certification Application. If reclaimed water is used as makeup to the Unit 5 cooling tower and cooling tower blowdown is returned to the South District Wastewater Treatment Plant, FPL shall apply for such permit from DERM as may be required under Chapter 24 of the Code of Miami-Dade County for such disposal pursuant to federal law.

XVII. FISH AND WILDLIFE CONSERVATION COMMISSION

Cooling Canal System Crocodile Population Protection

A. Continuation of Current Monitoring

The applicant shall continue with current crocodile monitoring efforts including identification surveys, breeding surveys, nest locations monitoring, and captures, and these efforts shall continue throughout the Unit 3 and Unit 4 uprating process.

B. Additional Monitoring

Specific protocols shall be followed for additional monitoring of crocodiles within the Turkey Point cooling canal system. These protocols based upon work by Mazzotti and Cherkiss shall be followed for the additional monitoring described below.

1. Surveys shall be conducted both pre- and post- Unit 3 and 4 uprate to determine any effects of temperature and salinity changes on crocodiles in the cooling canal

system. Surveys shall be initially conducted for a one-year period, after which protocols shall be reviewed for appropriateness. Any changes shall be submitted to the FWC.

2. Additional data shall be collected to determine changes in spatial distribution within the canal system. Data shall be collected monthly from the entire system. Monthly events shall consist of 3 to 4 nights per event, and data collected shall include animal size, GPS location, salinity, and air and water temperatures.

3. Additional data shall be collected to determine changes to growth and survival of crocodiles within the cooling canal system. The entire cooling canal system shall be monitored at least twice a year for five days and four nights per event. Data collected shall include biometric data for each individual hand captured or trapped.

4. If it is determined that there is a negative effect on crocodiles within the cooling canal system due to the Uprate project, the licensee shall monitor the crocodile population outside of the system, particularly in the FPL mitigation areas, to determine if there is no net negative effect. If growth and survival is affected within the system, then using telemetry data on crocodiles moving into and out of the system may show whether or not there is an overall change in the crocodile population at Turkey Point. A summary of monitoring efforts and results shall be included in the Annual Report.

5. If negative effects on crocodile habitat occur, as evidenced by monitoring of crocodile growth, population, and survivorship, FPL shall implement corrective actions in accordance with all applicable federal, state, and local regulatory requirements for the protection of endangered species habitat.

C. Annual Report

FPL shall submit an Annual Report including all data and statistical analyses resulting from the above monitoring requirements to FWC in order for FWC to assess changes in the crocodile population. The report shall be submitted beginning 12 months from initial monitoring, and every 12 months thereafter. Copies of these annual reports shall be provided to the DEP Siting Coordination Office, DERM and the Manager of the Biscayne Bay Aquatic Preserve. FPL shall notify DERM and the Manager of the Biscayne Bay Aquatic Preserve of any meeting with FWCC and DEP to address issues raised in these annual reports. [Chapter 68A – 27, F.A.C.; Miami-Dade CDMP Coastal Management – 1E]

XVIII. HISTORY

Unit 5 Certified on 02/07/05; signed by Governor Bush
Modified on 06/22/06; signed by Siting Administrator Oven
Modified on 04/24/07; signed by Siting Administrator Halpin
Units 3 & 4 Certified on 10/29/08; signed by Secretary Sole
Modified on 1/6/09; signed by Siting Administrator Halpin
Modified on 06/19/09; signed by Siting Administrator Halpin
Modified on 03/19/15 (E.1); signed by Deputy Secretary Cobb
Modified on 3/29/16 (E); signed by Governor Scott

SOUTH FLORIDA WATER MANAGEMENT DISTRICT

Regulation Division

June 29, 2021

Mr. Mike Sole
Florida Power & Light Company
700 Universe Blvd
Juno Beach, FL 33408

Subject: **FPL Turkey Point Conditions of Certification – Reclaimed Water Notification**

Dear Mr. Sole:

The South Florida Water Management District (SFWMD) is aware of the Miami-Dade County and Florida Power & Light (FPL) agreement to utilize treated reclaimed water at FPL's Turkey Point facility to serve as the primary cooling water source for the Unit 5 cooling towers. Accordingly, to comply with Condition XIII.C.2 of the Turkey Point Conditions for Certification, the SFWMD requires FPL to provide a schedule for use of reclaimed water for SFWMD review and approval.

Obtaining and utilizing reuse water to reduce demand for groundwater is consistent with the state's objective to encourage and promote reuse of reclaimed water ((Florida Statutes 403.064 and 373.250) and complies with Condition XIII.C.2 of the Turkey Point Conditions of Certification for using reclaimed water at the project site to serve Unit 5 for cooling purposes. Please note that, pursuant to Condition XIII.C.2, use of the Floridan aquifer water shall be reduced in proportion to the volume of reclaimed water made available to Unit 5

Sincerely,

Simon Sunderland, P.G.
Bureau Chief, Water Use
South Florida Water Management District

SS/ss

cc: Danielle Hall, FPL

MEMORANDUM

Agenda Item No. 8(O)(1)

TO:	Honorable Chairwoman Audrey M. Edmonson and Members, Board of County Commissioners	**DATE**:	June 16, 2020
FROM:	Abigail Price-Williams County Attorney	**SUBJECT:**	Resolution approving Agreement for Reclaimed Water Processing, Treatment and Use at the Florida Power & Light (FPL) Turkey Point Complex with FPL; authorizing annual payments to FPL until 2053 in a total amount not to exceed $182,000,000.00; and authorizing County Mayor to execute the Agreement and exercise the provisions contained therein including the negotiation and execution of an operating agreement

Resolution No. R-579-20

The accompanying resolution was prepared by the Water and Sewer Department and placed on the agenda at the request of Co-Prime Sponsors Commissioner Esteban L. Bovo, Jr. and Vice Chairwoman Rebeca Sosa, and Co-Sponsors Chairwoman Audrey M. Edmonson, Commissioner Sally A. Heyman, Commissioner Barbara J. Jordan, Commissioner Joe A. Martinez and Senator Javier D. Souto.

Abigail Price-Williams
County Attorney

APW/smm

Memorandum

MIAMI-DADE COUNTY

Date: June 16, 2020

To: Honorable Chairwoman Audrey M. Edmonson
and Members, Board of County Commissioners

From: Carlos A. Gimenez
Mayor

Subject: Resolution Approving Agreement for Reclaimed Water Processing, Treatment and Use at the Florida Power & Light Turkey Point Complex

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RECOMMENDATION

It is recommended that the Board of County Commissioners (Board) approve the attached resolution authorizing execution of a Reclaimed Water Services Agreement (Agreement) between the County, through its Water and Sewer Department (WASD), and Florida Power and Light Company (FPL) for the delivery of reclaimed water from the South District Wastewater Treatment Plant to the FPL facilities at Turkey Point. The Agreement is attached as Exhibit 1.

SCOPE

The impact of this Agreement is countywide, as it provides compliance of the County with the State Ocean Outfall Statute, and it facilitates the use of reclaimed water by FPL to improve overall environmental conditions at Turkey Point.

FISCAL IMPACT/FUNDING SOURCE

The County will pay from WASD operating revenues $6.5 million per year over the life of the Agreement through 2053 to support the project. Considering that the facility is scheduled to be operational beginning in 2026, the County is expected to undertake 28 payments, totaling $182 million. FPL will provide an estimated $300 million in capital costs and any additional operating costs needed to execute the project.

The County will be responsible for reimbursing FPL for the design and construction of any incremental facilities that the County requests to be constructed to enable the expansion of the facility for the treatment of additional reclaimed water for environmental or other uses. Any incremental facilities requested by the County are subject to Board approval. Additionally, the County expects to achieve the water quality parameters provided in the Agreement without any capital improvements to existing treatment facilities, and as such, additional costs related to reclaimed water quality standards are not anticipated. Although not anticipated, the County would be responsible for additional facilities that may be required by the County to meet such water quality standards.

DELEGATION OF AUTHORITY

Pursuant to section 5.03 of this Agreement, the County and FPL will also develop an operating agreement that will describe the operating protocols, communications, and reporting requirements for the safe and efficient operations of the Reclaimed Water Facility, in accordance with all applicable permits. This resolution delegates to the County Mayor or County Mayor's Designee the authority to negotiate and execute such operating agreement, provided that the operating agreement is (1) limited to operating protocols, communications, and reporting requirements of the Reclaimed Water Facility; (2) consistent with the provisions of the Reclaimed Water Services Agreement; and (3) results in no additional fiscal impact to the County beyond this Reclaimed Water Services Agreement.

TRACK RECORD/MONITOR

WASD's Assistant Director of Planning and Regulatory Compliance, Josenrique Cueto, P.E., will oversee the implementation of the Reclaimed Water Services Agreement.

BACKGROUND

On April 10, 2018, the Board approved Resolution No. R-292-18, authorizing the County Mayor or County Mayor's Designee to execute a Joint Participation Agreement with FPL for development of an Advanced Reclaimed Water Project and to further negotiate a Reclaimed Water Services Agreement to implement such a project, subject to Board approval. The discussion at that time focused on extensive treatment of reclaimed water from the South District Wastewater Treatment Plant for use in the restoration of the cooling canals at the Turkey Point complex.

After extensive analysis and discussion with WASD and the Division of Environmental Resources Management (DERM) staff, a more cost-effective project was developed. Under this plan, up to 15 million gallons per day (MGD) of reclaimed wastewater will be piped to Turkey Point, where it will receive additional treatment to make it suitable for use in the cooling towers for FPL's Unit five generating facility. Currently brackish water from the Floridan aquifer is being used for these cooling towers. The Floridan water will then become available to improve conditions in the cooling canals, providing additional environmental benefits.

Under the Agreement, FPL is responsible for designing and constructing the pipeline from the South District Wastewater Treatment Plant to the FPL facilities at Turkey Point, an advanced treatment system at Turkey Point to further treat the reclaimed water for use in the cooling towers, and additional pumping facilities at the South District plant should it be determined that additional capacity is required. The capital cost of all these facilities is currently estimated by FPL at $300 million.

The obligations of the parties are subject to both parties receiving necessary and appropriate permits, approvals and authorizations from regulatory authorities that support execution of the project and the County receiving approval from the Florida Department of Environmental Protection for the appropriate reclaimed credits for the duration of the Agreement.

The County will pay an annual fee of $6.5 million to FPL beginning when the County delivers reclaim water to FPL and continue over the life of the Agreement. The initial term of the Agreement expires at the end of 2053 and the Agreement automatically renews for five-year increments unless either party provides notice not to renew. This payment plan caps with certainty the annual financial obligation of the County, and it avoids potential disputes regarding operating costs and cost escalation provisions. The County investment is equivalent to that which was approved by the Board in 2010 when a larger reclaimed water project was authorized as part of

FPL's plans to construct two additional nuclear units at Turkey Point. That plan is no longer feasible.

Pursuant to provisions under the State Ocean Outfall Statute, the County is required to evaluate and implement reclaimed water projects that are technically, environmentally, and economically feasible. Because of the extraordinary water quality requirements for water in the Everglades system, it is extremely expensive and energy intensive to treat wastewater to acceptable standards. This project, which would be the fourth largest reclaimed water project in the State of Florida, presents an opportunity to use reclaimed wastewater in a more cost-effective way, and thereby free up Floridan aquifer water to be used for environmental enhancement purposes.

In order to facilitate the County's future reuse program, FPL has also agreed to design and build a second pipeline to Turkey Point and additional treatment capacity should the County and its partners determine feasible uses for additional reclaimed water in the area. Along with the County, South Florida Water Management District and other various State and Federal agencies are key stakeholders in the development and implementation of future reuse projects which benefit the environment. Further collaborative engagement is required to establish implementation and funding requirements that would enhance their efficacy. At the time that the appropriate funding partners are identified, the County will be in a position to readily expand the treatment facility and its reuse program.

Jack Osterholt
Deputy Mayor

MEMORANDUM
(Revised)

TO: Honorable Chairwoman Audrey M. Edmonson and Members, Board of County Commissioners

DATE: June 16, 2020

FROM: Abigail Price-Williams
County Attorney

SUBJECT: Agenda Item No. 8(O)(1)

Please note any items checked.

_______ **"3-Day Rule" for committees applicable if raised**

_______ **6 weeks required between first reading and public hearing**

_______ **4 weeks notification to municipal officials required prior to public hearing**

_______ **Decreases revenues or increases expenditures without balancing budget**

_______ **Budget required**

_______ **Statement of fiscal impact required**

_______ **Statement of social equity required**

_______ **Ordinance creating a new board requires detailed County Mayor's report for public hearing**

_______ **No committee review**

_______ **Applicable legislation requires more than a majority vote (i.e., 2/3's present ____, 2/3 membership ____, 3/5's ____, unanimous ____, CDMP 7 vote requirement per 2-116.1(3)(h) or (4)(c) ____, CDMP 2/3 vote requirement per 2-116.1(3)(h) or (4)(c) ____, or CDMP 9 vote requirement per 2-116.1(4)(c)(2) ____) to approve**

_______ **Current information regarding funding source, index code and available balance, and available capacity (if debt is contemplated) required**

Approved ______________________ Mayor
Veto __________
Override __________

Agenda Item No. 8(O)(1)
6-16-20

RESOLUTION NO. R-579-20

RESOLUTION APPROVING AGREEMENT FOR RECLAIMED WATER PROCESSING, TREATMENT AND USE AT THE FLORIDA POWER & LIGHT (FPL) TURKEY POINT COMPLEX WITH FPL; AUTHORIZING ANNUAL PAYMENTS TO FPL UNTIL 2053 IN A TOTAL AMOUNT NOT TO EXCEED $182,000,000.00; AND AUTHORIZING COUNTY MAYOR OR COUNTY MAYOR'S DESIGNEE TO EXECUTE THE AGREEMENT AND EXERCISE THE PROVISIONS CONTAINED THEREIN INCLUDING THE NEGOTIATION AND EXECUTION OF AN OPERATING AGREEMENT

WHEREAS, this Board desires to accomplish the purposes outlined in the accompanying memorandum, a copy of which is incorporated herein by reference,

NOW, THEREFORE, BE IT RESOLVED BY THE BOARD OF COUNTY COMMISSIONERS OF MIAMI-DADE COUNTY, FLORIDA, that this Board approves the Agreement for Reclaimed Water Processing, Treatment and Use at the Florida Power & Light Turkey Point Complex with Florida Power & Light; authorizing annual payments to FPL until 2053 in a total amount not to exceed $182,000,000.00; and authorizes the County Mayor or County Mayor's designee to execute the Agreement, in substantially the form attached to the accompanying County Mayor's Memorandum, and to exercise the provisions contained therein including the negotiation and execution of an operating agreement.

The foregoing resolution was offered by Commissioner **Rebeca Sosa**, who moved its adoption. The motion was seconded by Commissioner **Esteban L. Bovo, Jr.** and upon being put to a vote, the vote was as follows:

Audrey M. Edmonson, Chairwoman **aye**
Rebeca Sosa, Vice Chairwoman **aye**

Esteban L. Bovo, Jr.	**aye**	Daniella Levine Cava	**aye**
Jose "Pepe" Diaz	**aye**	Sally A. Heyman	**aye**
Eileen Higgins	**aye**	Barbara J. Jordan	**absent**
Joe A. Martinez	**absent**	Jean Monestime	**aye**
Dennis C. Moss	**aye**	Sen. Javier D. Souto	**absent**
Xavier L. Suarez	**aye**		

The Chairperson thereupon declared this resolution duly passed and adopted this 16th day of June, 2020. This resolution shall become effective upon the earlier of (1) 10 days after the date of its adoption unless vetoed by the County Mayor, and if vetoed, shall become effective only upon an override by this Board, or (2) approval by the County Mayor of this resolution and the filing of this approval with the Clerk of the Board.

MIAMI-DADE COUNTY, FLORIDA
BY ITS BOARD OF
COUNTY COMMISSIONERS

HARVEY RUVIN, CLERK

By: **Melissa Adames**
Deputy Clerk

COUNTY COMMISSIONERS
MIAMI-DADE COUNTY FLORIDA

Approved by County Attorney as
to form and legal sufficiency.

Henry N. Gillman

2022 Merged ECRC Project	Previously Approved ECRC Projects to be Combined	Regulatory Requirement
1 - Air Operating Permit Fees (O&M)	Gulf- 2-Air Emission Fees (O&M) FPL-1 - Air Operating Permit Fees (O&M)	Title V of the Clean Air Act Amendments of 1990
2 - Low NOX Burner Technology (Capital)	Gulf- 4-Low NOx Burners, Crist 6 & 7 (Capital) FPL-2 - Low NOX Burner Technology (Capital)	Clean Air Act Amendments of 1990
3 - Continuous Emissions Monitoring Systems (O&M & Capital)	Gulf- 5-Emission Monitoring (O&M); 5- Continuous Emission Monitoring Systems (CEMS)- (Capital) FPL- 3 - Continuous Emissions Monitoring Systems (O&M & Capital)	Clean Air Act Amendments of 1990; 40 CFR Part 75
5 - Maintenance of Stationary Above Ground Fuel Storage Tanks (O&M & Capital)	Gulf - 12-Aboveground Storage Tanks (O&M) FPL - 5 - Maintenance of Stationary Above Ground Fuel Storage Tanks (O&M & Capital)	Florida Aboveground Storage Tank Regulation, Chapter 62-762, F.A.C.
14 - NPDES Permit Fees (O&M)	Gulf - 8-State NPDES Administration (O&M) FPL - 14 - NPDES Permit Fees (O&M)	Florida Permits Regulation, 62-4.052, F.A.C.
19 - Oil-filled Equipment and Hazardous Substance Remediation (O&M and Capital)	Gulf - 6- Substation Contamination Remediation (Capital); 7- Groundwater Contamination Investigation (O&M) FPL- 19 - Substation Pollutant Discharge Prevention & Removal (O&M)	Florida Contaminated Site Cleanup Criteria, Chapter 62-780, F.A.C.; Florida Statute Chapters 376 and 403
23- SPCC Program (O&M and Capital)	Gulf- 20- SPCC Compliance (Capital); 11-Crist Bulk Tanker Unloading Secondary Containment (Capital) 11- SPCC O&M costs from General Solid & Hazardous Waste Project (O&M) FPL-23- SPCC Program (Capital & O&M)	Federal Spill Prevention Control and Countermeasures regulation, 40 CFR Part 112
27 - Lowest Quality Water Source (O&M & Capital)	Gulf - Smith Water Conservation (Capital-17 and O&M- 24) Crist Water Conservation (Capital-24 and O&M- 22) 7 - Raw Water Well Flowmeters - Plants Crist and Smith (Capital) FPL - 27 - Lowest Quality Water Source (O&M)	Facility Consumptive Use Permits issued by Florida Water Management Districts
28 - CWA 316(b) Phase II Rule (O&M and Capital)	Gulf - 30-316(b) Cooling Water Intake Structure Regulation (Capital) 6 - 316(b) O&M costs from General Water Quality (O&M) FPL - 28 - CWA 316(b) Phase II Rule (O&M & Capital)	Federal Cooling Water Intake Structure Regulations, 40 CFR Part 122 and 125
426 - Air Quality Compliance (O&M and Capital)	Gulf- Air Quality Compliance Program (Capital-26 and O&M-20) FPL-31 - Clean Air Interstate Rule (CAIR) Compliance (O&M & Capital) 29 - SCR Consumables (O&M) 33 - MATS Project (O&M & Capital) 45 - 800 MW Unit ESP (Capital)	Federal National Ambient Air Quality Standards, Clean Air Interstate Rule (CAIR) and its replacement rule Cross-State Air Pollution Rule (CSAPR), Clean Air Mercury Rule (CAMR) and its replacement rule Mercury and Air Toxics Standard (MATS), Facility Site Certification Amendments and PSD Air Construction Permit. Georgia Multi-Pollutant Rule
47 - NPDES Permit Renewal Requirements (O&M & Capital)	Gulf - 9-Crist Dechlorination System (Capital) 12-Crist IWW Sampling System (Capital) 25-Plant NPDES Permit Compliance Projects (Capital) 6-Toxicity sampling costs from General Water Quality (O&M) FPL - 47 - NPDES Permit Renewal Requirements (O&M & Capital)	State NPDES Industrial Wastewater Regulation, Chapter 62-660, F.A.C. and associated permits
50 - Steam Electric Effluent Limitations Guidelines Revised Rules (O&M and Capital)	Gulf - 29-Steam Electric Effluent Limitations Guidelines (Capital) FPL - 50 - Steam Electric Effluent Guidelines Revised Rules (O&M and Capital)	Federal Steam Effluent Limitations Guidelines, 40 CFR Part 423
54 - Coal Combustion Residuals (Capital)	Gulf- 28 (Capital) and 23-Coal Combustion Residuals (O&M) FPL- 54 - Coal Combustion Residuals (Capital)	Federal CCR regulation, 40 CFR Parts 257 and 261; Georgia CCR rule, NPDES industrial wastewater permits
Emission Allowances (O&M and Capital)	Gulf- Allowances (Capital and O&M-27) FPL- Capital	Federal Acid Rain program developed under Clean Air Act Amendments of 1990, Cross-State Air Pollution Rule (CSAPR)

St. Johns River Water Management District

Ann B. Shortelle, Ph.D., Executive Director

4049 Reid Street • P.O. Box 1429 • Palatka, FL 32178-1429 • 386-329-4500 • www.sjrwmd.com

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20210007-EI EXHIBIT: 19
PARTY: MWS-14
DESCRIPTION: Sanford Plant July 13, 2021 Consumptive Use Permit

July 13, 2021

Pete Holzapfel
Florida Power & Light Company
950 S Charles Richard Beall Blvd
DeBary, FL 32713-9746

SUBJECT: Florida Power & Light Company Sanford Plant, Consumptive Use Permit Number 9202-6
Volusia County, Florida

Dear Sir/Madam:

Enclosed is the permit authorized by the District on July 13, 2021. The enclosed permit is a legal document and should be kept with other important records. Please read the permit and conditions carefully because the referenced conditions may require submittal of additional information. Where possible, please submit all information required to comply with permit conditions electronically at www.sjrwmd.com/permitting via the District's e-Permitting portal.

Please be advised that the period of time within which a third party may request an administrative hearing on this permit may not have expired by the date of issuance. A potential petitioner has 26 days from the date on which the actual notice is deposited in the mail, or 21 days from publication of this notice when actual notice is not provided, within which to file a petition for an administrative hearing pursuant to Sections 120.569 and 120.57, Florida Statutes. Receipt of such a petition by the District may result in this permit becoming null and void.

If you have any questions concerning the permit, please contact Callie Register in the Palm Bay Service Center at (321) 473-1328 or Kristian Holmberg in the Palm Bay Service Center at (321) 409-2121

Sincerely,

Rich Burklew

Richard Burklew, Bureau Chief
Water Use Regulation

ST. JOHNS RIVER WATER MANAGEMENT DISTRICT
Post Office Box 1429
Palatka, Florida 32178-1429

PERMIT NO: 9202-6 **DATE ISSUED:** July 13, 2021

PROJECT NAME: Florida Power & Light Company Sanford Plant

A PERMIT AUTHORIZING:
The District authorizes, as limited by the attached conditions, the use of 5,475.00 million gallons per year (mgy) (15 million gallons per day (mgd annual average)) from the St. Johns River and 103.7 mgy (0.28 mgd, annual average) of groundwater from the Upper Floridan aquifer (through 2023) for commercial / industrial use in power generation through 2041.

LOCATION:
Site: Florida Power & Light Company
Volusia County

SECTION(S):	TOWNSHIP(S):	RANGE(S):
22, 31, 32	18S	30E
4, 5, 6, 7, 8, 9, 16, 17	19S	30E

ISSUED TO:
Florida Power & Light Company
950 S Charles Richard Beall Blvd
DeBary, FL 32713-9746

The permittee agrees to hold and save the St. Johns River Water Management District and its successors harmless from any and all damages, claims, or liabilities which may arise from permit issuance. Said application, including all plans and specifications attached thereto, is by reference made a part hereof.

This permit does not convey to the permittee any property rights nor any rights or privileges other than those specified herein, nor relieve the permittee from complying with any applicable local government, state, or federal, rule, or ordinance.

This permit may be revoked, modified, or transferred at any time pursuant to the appropriate provisions of Chapter 373, Florida Statutes and 40C-1, Florida Administrative Code.

PERMIT IS CONDITIONED UPON:
See conditions on attached "Exhibit A", dated July 13, 2021

AUTHORIZED BY: St. Johns River Water Management District
Division of Regulatory Services

By: ______________________________
Ann Shortelle
Executive Director

"EXHIBIT A"
CONDITIONS FOR ISSUANCE OF PERMIT NUMBER 9202-6
Florida Power & Light Company Sanford Plant
DATE ISSUED July 13, 2021

1. With advance notice to the permittee, District staff with proper identification shall have permission to enter, inspect, observe, collect samples, and take measurements of permitted facilities to determine compliance with the permit conditions and permitted plans and specifications. The permittee shall either accompany District staff onto the property or make provision for access onto the property.

2. Nothing in this permit should be construed to limit the authority of the St. Johns River Water Management District to declare a water shortage and issue orders pursuant to Chapter 373, F.S. In the event of a declared water shortage, the permittee must adhere to the water shortage restrictions, as specified by the District. The permittee is advised that during a water shortage, reports shall be submitted as required by District rule or order.

3. Prior to the construction, modification or abandonment of a well, the permittee must obtain a water well permit from the St. Johns River Water Management District or the appropriate local government pursuant to Chapter 40C-3, F.A.C. Construction, modification, or abandonment of a well will require modification of the consumptive use permit when such construction, modification, or abandonment is other than that specified and described on the consumptive use permit application form.

4. Leaking or inoperative well casings, valves, or controls must be repaired or replaced as required to eliminate the leak or make the system fully operational.

5. The permittee's consumptive use of water as authorized by this permit shall not interfere with legal uses of water existing at the time of permit application. If interference occurs, the District shall revoke the permit, in whole or in part, to curtail or abate the interference, unless the interference associated with the permittee's consumptive use of water is mitigated by the permittee pursuant to a District-approved plan.

6. The permittee's consumptive use of water as authorized by this permit shall not have significant adverse hydrologic impacts to off-site land uses existing at the time of permit application. If significant adverse hydrologic impacts occur, the District shall revoke the permit, in whole or in part, to curtail or abate the adverse impacts, unless the impacts associated with the permittee's consumptive use of water are mitigated by the permittee pursuant to a District-approved plan.

7. The permittee shall notify the District in writing within 30 days of any sale, transfer, or conveyance of ownership or any other loss of permitted legal control of the Project and/or related facilities from which the permitted consumptive use is made. Where permittee's control of the land subject to the permit was demonstrated through a lease, the permittee must either submit documentation showing that it continues to have legal control or transfer control of the permitted system/project to the new landowner or new lessee. All transfers of ownership are subject to the requirements of Rule 40C-1.612, F.A.C. Alternatively, the permittee may surrender the consumptive use permit to the District, thereby relinquishing the right to conduct any activities under the permit.

8. A District-issued identification tag shall be prominently displayed at each withdrawal site by permanently affixing such tag to the pump, headgate, valve, or other withdrawal facility as provided by Rule 40C-2.401, F.A.C. The permittee shall notify the District in the event that a replacement tag is needed.

9. The permittee's consumptive use of water as authorized by this permit shall not adversely impact wetlands, lakes, rivers, or springs. If adverse impacts occur, the District shall revoke the permit, in whole or in part, to curtail or abate the adverse impacts, unless the impacts associated with the permittee's consumptive use of water are mitigated by the permittee pursuant to a District-approved plan.

10. The permittee's consumptive use of water as authorized by this permit shall not reduce a flow or level below any minimum flow or level established by the District or the Department of Environmental Protection pursuant to Section 373.042 and 373.0421, F.S. If the permittee's use of water causes or contributes to such a reduction, then the District shall revoke the permit, in whole or in part, unless the permittee implements all provisions applicable to the permittee's use in a District-approved recovery or prevention strategy.

11. The permittee's consumptive use of water as authorized by the permit shall not cause or contribute to significant saline water intrusion. If significant saline water intrusion occurs, the District shall revoke the permit, in whole or in part, to curtail or abate the saline water intrusion, unless the saline water intrusion associated with the permittee's consumptive use of water is mitigated by the permittee pursuant to a District-approved plan.

12. The permittee's consumptive use of water as authorized by the permit shall not cause or contribute to flood damage. If the permittee's consumptive use causes or contributes to flood damage, the District shall revoke the permit, in whole or in part, to curtail or abate the flood damage, unless the flood damage associated with the permittee's consumptive use of water is mitigated by the permittee pursuant to a District-approved plan.

13. All consumptive uses authorized by this permit shall be implemented as conditioned by this permit, including any documents incorporated by reference in a permit condition. The District may revoke this permit, in whole or in part, or take enforcement action, pursuant to Section 373.136 or 373.243, F.S., unless a permit modification has been obtained to address the noncompliance. The permittee shall immediately notify the District in writing of any previously submitted information that is later discovered to be inaccurate.

14. The permittee shall use the lowest quality water source, such as reclaimed water, surface/storm water, or alternative water supply, to supply the needs of the project when deemed feasible pursuant to District rules and applicable state law.

15. This permit does not convey to the permittee any property rights or privileges other than those specified herein, nor relieve the permittee from complying with any applicable local government, state, or federal law, rule, or ordinance.

16. A permittee may seek modification of any term of an unexpired permit. The permittee is advised that Section 373.239, F.S., and Rule 40C-2.331, F.A.C., are applicable to permit modifications.

17. This permit will expire on July 13, 2041.

18. Maximum annual groundwater withdrawals for commercial / industrial use must not exceed 103.7 million gallons (0.284 million gallons per day (mgd) average) in 2021 through 2023.

19. The maximum annual surface water use must not exceed 5,475.00 million gallons (15.00 million gallons per day (mgd) average) for commercial / industrial use in 2021 through 2041. Annual surface water withdrawals, including amounts for circulation through the existing intake structure, must not exceed 50,445 million gallons (138.21 mgd average).

20. The permittee must operate wells 3 (station ID 17680) and 4 (station ID 17681) for backup use only beginning no later than August 1, 2023. Both of these wells must be properly abandoned by August 1, 2024.

21. Pumps SW-1 (Station ID 497528) and SW-2 (Station ID 497537), CW3A (Station ID 2956), CW3B (Station ID 2957), LF3A (Station ID 22457), and LF3B (Station ID 22456), and wells 3 (Station ID17680) and 4 (Station ID 17681) must be equipped with totalizing flow meters or an alternative method for measuring flow must be implemented. Withdrawals from the ground water wells are measured utilizing a totalizing in-line flow meter. The totalizing flow meter must maintain a 95% accuracy, be verifiable and be installed according to manufacturer specifications.

The permittee has elected to implement an alternative method for pumps SW-1 (Station ID 497528), SW-2 (Station ID 497537), CW3A (Station ID 2956), CW3B (Station ID 2957), LF3A (Station ID 22457), and LF3B (Station ID 22456) where the pump on/off times are electronically recorded. The flow is determined using the running times of the pumps and the appropriate pump log curves and pump rate as a basis for calculating the quantity of water withdrawn from the St Johns River. The permittee may not alter the approved alternative method without prior written approval from the District. The method must maintain 90% accuracy and be verifiable.

22. Total withdrawal, from pumps SW-1 (Station ID 497528) and SW-2 (Station ID 497537), CW3A (Station ID 2956), CW3B (Station ID 2957), LF3A (Station ID 22457), and LF3B (Station ID 22456) and well numbers 3 (Station ID 17680) and 4 (Station ID 17681), as listed on the application, must be recorded continuously, totaled monthly, and reported to the District every six months for the duration of the permit using District Form No. EN-50. The reporting dates each year will be as follows:

Reporting Period	Report Due Date
January-June	July 31
July-December	January 31

23. The permittee must implement the Water Conservation Plan submitted to the District on June 8, 2020, in accordance with the schedule contained therein.

24. The permittee must maintain all flowmeters and alternative methods for measuring flow. In case of failure or breakdown of any meter, the District must be notified in writing within 5 days of its discovery. A defective meter must be repaired or replaced within 30 days of its discovery.

25. In order to ensure that the volume of water withdrawn and recorded by the permittee is accurate to within +/- 5% of actual flow (+/- 10% of flow when using an alternative method), the meter accuracy or flow rate from each withdrawal point must be validated once every 10 years and recorded on either the Flow Meter Accuracy Report Form (EN-51) or Alternative Method Flow Verification Report Form (whichever form is applicable). The validation documents must be provided to the District upon request.

26. The permittee shall submit, to the District, a compliance report pursuant to subsection 373.236(4), F.S., every 10 years during the term of the permit. The permittee shall submit the report by July 13, 2031. The report shall contain sufficient information to demonstrate that the permittee's use of water will continue, for the remaining duration of the permit, to meet the conditions for permit issuance set forth in the District rules that existed at the time the permit was issued for 20 years by the District. At a minimum, the compliance report must:

    - meet the submittal requirements of section 4.2 of the Applicant's Handbook: Consumptive Uses of Water, August 29, 2018;
    - include documentation verifying that the source is capable of supplying the needs authorized by this permit without causing harm to water resources;
    - include documentation verifying that the permittee is implementing all feasible water conservation measures;
    - document that the lowest acceptable quality water source, including reclaimed water or surface water (which includes storm water), must be utilized for each consumptive use;
    - ensure that all monitoring requirements are met;
    - and include information documenting that the projected allocation is needed.

CONSUMPTIVE USE TECHNICAL STAFF REPORT
13-Jul-2021
APPLICATION #: 9202-6

Owner: Pete Holzapfel
Florida Power & Light Company
950 S Charles Richard Beall Blvd
DeBary, FL 32713-9746
(386) 575-5211

Applicant: Same as Owner

Agent: Not Applicable

Compliance Contact: Kelly A Napoli
700 Universe Blvd
Juno Beach, FL 33408-2657
(561) 694-4015

Greg Boswell
Florida Power & Light
950 S Highway 17 92
Debary, FL 32713-9746
(386) 575-5243

Project Name: Florida Power & Light Company Sanford Plant
County: Volusia

Objectors: No

Authorization Statement:
The District authorizes, as limited by the attached conditions, the use of 5,475.00 million gallons per year (mgy) (15 million gallons per day (mgd annual average)) from the St. Johns River and 103.7 mgy (0.28 mgd, annual average) of groundwater from the Upper Floridan aquifer (through 2023) for commercial / industrial use in power generation through 2041.

Recommendation: Approval
Reviewers: Callie Register; Kristian Holmberg

Abstract:

This is a renewal of an existing commercial / industrial permit with a 92% reduction in surface water allocation and a 100% decrease in groundwater use. Total water allocated for plant processes and cooling is up to 5,475.00 mgy (15 mgd) of surface

water through 2041 and 103.7 mgy (0.28 mgd) of groundwater through 2024 when groundwater use will be discontinued. Surface water from the St. Johns River is also used for circulation through the power plant's cooling pond and intake / discharge structure, thus up to 50,445 mgy (138.21 mgd) of surface water will be withdrawn and discharged back to the St. Johns River. Previously, total pumped amounts were allocated and did not reflect the amount discharged back to the river. The allocation reflects only the amount of water that will be consumed, not re-circulated. In addition, the actual pumped surface water amount is decreasing by approximately 23% (from 180.22 to 138.21 mgd) because of system efficiency improvements. Staff is recommending a 20-year permit duration with 10-year compliance reporting.

PROJECT DESCRIPTION

<u>Project Location</u>:
The Florida Power and Light (FPL) Sanford Plant (the Plant) is located in the City of DeBary in Volusia County. U.S. Highway 17-92 is adjacent to the Plant on the eastern border of the property, and the St. Johns River basin is adjacent to the Plant on the south / southwest property boundary. The surface water pumps are located on a canal immediately downstream of Lake Monroe, in the Middle St. Johns River basin. The groundwater wells are located approximately five miles north of the Plant within the Volusia Blue Spring-shed.

<u>Background</u>:
The FPL-Sanford Plant was originally constructed in 1929. Unit 1 operated until 1964 and unit 2 from 1947-1964. In 2003, the Plant underwent re-powering to expand the system generating capacity and improve Plant efficiency by installing new equipment and utilizing modern processes at three generating units, units 3, 4, and 5. The re-powering resulted in a 43% reduction in groundwater use. At that time, the facility connected to the Volusia County potable water line rather than supply potable water to the facility via the on-site Upper Floridan aquifer wells as historically done. In 2012, unit 3 was retired and currently the Plant consists of two steam electric generating units (units 4 and 5) with a total nameplate megawatt (MW) output of 2,232 MW. Units 4 and 5 are natural gas-fired combined cycle units.

<u>Water Use Description</u>:
The primary consumptive use of surface water at the site is to replace water lost to evaporation in a closed recirculating cooling water system within a 1,100-acre cooling pond north of the Plant. The cooling pond water is primarily made up of power generation process water with some contributions from stormwater collected at the site and water from the St. Johns River. The overall volume of the cooling pond is 3.1 billion gallons. Units 4 and 5 main condenser cooling water system uses water drawn from the cooling pond to cool the steam condensers. There is an annual average cooling pond blowdown of approximately 5,000 gallons per minute (gpm). The cooling pond system is closed with no regular discharges, except for testing and emergency releases. Over the past five years, the site used up to 11.8 mgd of water from the St. Johns River for the Cooling Pond. The Cooling Pond is a dam and must operate within a specific water

level range for dam safety purposes. The Plant, in order to adhere to dam safety protocols may need to discharge water to the St. Johns River in order to prepare for a large amount of rainfall. After a storm event, it may be necessary to re-fill the Cooling Pond from the St. Johns River. The amount of surface water proposed for cooling (14.5 mgd) accounts for the historic average amount used to replenish evaporative losses plus an estimated amount needed in case of emergency to re-fill the Pond. In addition, the Plant will continue to withdraw surface water to blend with plant waste stream water and recirculate to the St. Johns River through the Plant's unit 3 intake and discharge canal.

Current supply to the Plant's water treatment facility's Ultrafiltration System and Reverse Osmosis is a blended source of feed water comprised of groundwater (approximately 300-400 gpm) and water from the cooling pond (also approximately 300-400 gpm). Groundwater is used at the site for process water, service water and fire suppression. As part of this renewal, all of these groundwater uses will switch to other sources and the wells will be abandoned. At that time, process water uses will be provided by treated surface water (up to 0.50 mgd) and service water (approximately 0.012 mgd) and fire suppression needs will be provided by Volusia County potable supply, as needed. FPL needs to maintain the groundwater supply for the process water system at the facility until the switch to surface water comes on line by August 2023. In addition, a backup groundwater supply is being provided for redundancy and testing during the first year after the switch from groundwater to surface water in years 2023 - 2024. After the testing period is over, FPL will abandon wells 3 (station ID 17680) and 4 (station ID 17681) by December 31, 2024. Until well abandonment, the groundwater flows will continue to be measured using in-line flowmeters. The ability to switch from groundwater to St. Johns River water is contingent on Florida Department of Environmental Protection approval.

The Plant currently has four active pumps: the cooling pond pumps (LF3A/3B) and the circulating water pumps (CW3A/3B). Two surface water pumps (OCW 3A and 3B) were removed in 2014 and will be replaced with a new single pumping structure (including proposed pumps SW-1 and SW-2). Pumps SW-1 and SW-2 will provide the water to replace groundwater use. The six surface water pumps (four active and two proposed) measure and record flow with a District-approved alternative method. The Plant uses a Distributed Control System (DCS) input and calculation for the Unit 3 circulating water pumps (Pumps CW3A and CW3B) and the Sanford Plant Industrial Cooling Pond makeup pumps (LF3A & LF3B). An input signal to the DCS is fed from the main breaker for each pump motor. The input signal lets the DCS know whether the pump motor breaker is open (pump off) or the pump motor breaker is closed (pump on). The DCS looks at this signal every second and applies the appropriate pump rate (from the pump curve) as the basis for calculating the water withdrawal (minutes operating times gallons per minute) for each pump and sends that value to a daily accumulator calculator. The daily totals are saved in an archive file. Realtime accumulated flow as well as the archived daily flow can be viewed via the DCS interface to the Sanford Plant's computer system. Water flows for each pump are reviewed and verified on a regular basis by

Plant personnel and maintained at greater than 90% accuracy as required by the permit.

PERMIT APPLICATION REVIEW:

Section 373.223, *Florida Statutes* (F.S.), and Section 40C-2.301, Florida Administrative Code (F.A.C.), require an applicant to establish that the proposed use of water:

(a) is a reasonable-beneficial use;
(b) will not interfere with any presently existing legal use of water; and,
(c) is consistent with the public interest.

In addition, the above requirements are detailed further in the District's Applicant's Handbook: Consumptive Uses of Water, August 29, 2018 ("A.H.") District staff has reviewed the consumptive use permit application pursuant to the above-described requirements and has determined that the application meets the conditions for issuance of this permit. A summary of the staff review is provided below.

REASONABLE BENEFICIAL USE CRITERIA:

<u>Economic and Efficient Utilization</u>:
The permittee operates on natural gas which minimizes the facility's overall water use. The permittee's water use has been well within allocation since the permit was issued. The permittee has significantly decreased surface water use since the previous permit was issued due to re-powering and more efficient steam turbine installation. Therefore, a 23% decrease in surface water pumping is proposed at this time. In addition, FPL is maximizing its use of a lower quality source (surface water from the St. Johns River) while eliminating use of groundwater.

<u>Water Conservation</u>:
The Plant has previously reduced total use by 33% and groundwater use by 43% upon re-powering in 2003. FPL continues to strive towards greater water conservation and implements an existing leak detection and repair program. Additional water conservation efforts include:

- Use of sub-metering to more accurately account for water use and detect / address leaks.
- Use of flow meters to monitor water use on existing groundwater wells.
- Decrease in water use due to installation of more efficient steam turbines.
- Low volume fixtures in office facilities.
- The facility does not irrigate any landscape areas within the property boundary because water-efficient landscaping has been used.
- Inspection Of Watch (IOW): Technicians are assigned an area of responsibility to inspect all of their assigned equipment / process areas and identify malfunctions (leaks). Leaks will be immediately corrected by the technician or the Plant’s maintenance group. IOW is performed every day and covers the entire Plant.

- Equipment monitoring: FPL utilizes continuous digital trend monitoring of equipment operations and processes from which deviations can be discerned. Significant deviations will create an alarm in the control room notifying a technician to inspect the equipment / process in question and determine appropriate follow up, correct minor issues, or create a work ticket for larger items.
- Steam traps and lines are regularly checked for leaks, steam condensate is returned to boilers, and an automatic blowdown control has been installed to better manage the treatment of makeup water.
- Water conservation has been incorporated into the Plant's environmental employee training and awareness program and has been incorporated into the Plant's environmental updates for employees.
- The facility completed an alternative flow measurement verification demonstrating 90% accuracy as required by the permit.

<u>Suitability and Capability of the Source</u>:
The St. Johns River has historically and continues to be capable of supplying water to meet the water requirements of this project. The Unit 3 open cooling water pumps OCW3A and OCW3B (station IDs 22455 and 22454, respectively) have been removed, resulting in a decrease in surface water use. These pumps are intended to be replaced with a new, single pumping structure, including pumps SW-1 and SW-2 (station IDs 497528 and 497537, respectively).

The District’s 2012 Water Supply Impact Study (WSIS) evaluated the effects of water withdrawals from the St. Johns and Ocklawaha Rivers. The WSIS indicates an appreciable quantity of surface water can be safely withdrawn from the St. Johns River with minimal to negligible environmental effects. The St. Johns River continues to be suitable and capable of producing the proposed decreased surface water withdrawal.

<u>Lowest Acceptable Quality Water Source</u>:
The applicant currently utilizes a lower quality source of surface water and stormwater for the majority of cooling and Plant processes. Groundwater is currently used for process water and fire suppression at the site. There are three potential sources at the site to offset or eliminate the groundwater use: (1) reclaimed water from Volusia County, (2) surface water from the St. Johns River, and / or (3) cooling pond water. Due to dam safety requirements, FPL cannot increase the amount of cooling pond water used for process water, therefore, FPL provided feasibility analyses investigating the use of reclaimed and St. Johns River water.

The evaluation for use of reclaimed indicated that there are significant environmental constraints on brine discharge to the river. To avoid the environmental impacts of such discharges, FPL evaluated the costs associated with discharging to the Volusia County sewer system using published rates. Estimated capital costs associated with the use of reclaimed water total approximately $5.0 million, while estimated capital costs for using surface water instead of groundwater total approximately $3.2 million. Estimated increased Operations and Maintenance (O&M) costs associated with the use of reclaimed water total approximately $240,160, while estimated O&M costs for using surface water instead of groundwater total approximately $142,360.

Based on the evaluation of technical, environmental, and economic considerations, surface water is deemed an appropriate lower quality source for the site. FPL has committed to switching from groundwater to surface water and potable water within three years and, at that time, abandoning the two groundwater wells remaining for the Plant.

Water Resources Impact Evaluation:
A consumptive use must not cause harm to either onsite or offsite water resources, including lakes, wetlands or other existing offsite land uses. Staff evaluated if the proposed consumptive use would cause harmful hydrologic alterations to natural systems, including wetlands and other surface waters located on and off-site. Previous evaluations conducted by District staff to observe the condition of wetlands and surface waters in the vicinity of the project site did not reveal any impact to the wetlands resulting from the permittee's withdrawals of water from the St. Johns River. This application proposes a 23% decrease in surface water use, a 92% decrease in surface water allocation, and a 100% decrease in groundwater use after three years through the abandonment of the two remaining groundwater wells. Staff determined that the proposed use would not alter the existing hydrology and cause an unmitigated adverse impact to natural systems, including wetlands or other surface waters.

Minimum Flows and Levels:
There are numerous water bodies with adopted minimum flows and levels (MFLs) in Volusia County. Staff evaluated whether the Plant's surface water source would be capable of producing the continued use of water without impacting the MFL established for Lake Monroe. Lake Monroe is part of the Middle St. Johns River basin and is approximately 9,400 acres in size. The Plant proposes continued use of approximately 15 mgd from the St. Johns River just downstream of Lake Monroe. As discussed previously, the WSIS study supports the availability of surface water at the site.

The closest MFL waterbodies to the FPL-Sanford wells include Lake Butler, Gemini Springs and Blue Spring. An evaluation was made of the cumulative drawdown effects on these waterbodies resulting from the proposed abandonment of the groundwater wells associated with the FPL-Sanford site. The analysis indicates minor benefits to Lake Butler and Gemini Springs and an increase in flow to Blue Spring. Staff conclude that reasonable assurance has been provided that the proposed use will not result in a violation of MFLs, if the permittee complies with all conditions of the permit.

Water Reserved from Use:
This criterion is met. There are no water reservations in Volusia County pursuant to subsection 373.223(4), Florida Statues, that could be impacted by this withdrawal.

Saline Water Intrusion:

Staff completed a water quality trend analysis for Well 3 (Station ID 17680) using data from 2011-2020. The analysis shows that chlorides from the well have remained consistently less than 60 mg/L. Due to the low levels of chlorides and the proposed elimination of groundwater use within four years, staff is recommending discontinuing water quality sampling.

INTERFERENCE WITH EXISTING LEGAL USES:
There have been no reports of interference with existing legal uses as a result of the permittee's surface or groundwater withdrawals. District staff concluded that reasonable assurances have been provided that the use will not cause or contribute to interference with existing legal uses for the duration of the permit, provided the permittee complies with the conditions recommended for this permit.

PUBLIC INTEREST:
The proposed use will not adversely affect water resources, qualifies as a reasonable-beneficial use, and none of the reasons for denial relating to salt-water intrusion, water use reservations, minimum flows and levels, and water table/surface water levels apply to the proposed use. Therefore, staff concluded that reasonable assurances have been provided that the proposed use is consistent with the public interest.

Station Information
Site Name: Florida Power & Light Company

Well Details								
District ID	**Station Name**	**Casing Diameter (inches)**	**Casing Depth (feet)**	**Total Depth (feet)**	**Capacity (GPM)**	**Source Name**	**Status**	**Use Type**
17680	3	10	84	280	200	FAS - Upper Floridan Aquifer	Active	Commercial/Industrial/ Institutional
17681	4	10	84	350	200	FAS - Upper Floridan Aquifer	Active	Commercial/Industrial/ Institutional

Pump Details						
District ID	**Station Name**	**Pump Intake Diameter (inches)**	**Capacity (GPM)**	**Source Name**	**Status**	**Use Type**
2956	CW3A	54	58000	Saint Johns River	Active	Commercial/Industrial/ Institutional
2957	CW3B	54	58000	Saint	Active	Commercial/Industrial/

Pump Details						
District ID	Station Name	Pump Intake Diameter (inches)	Capacity (GPM)	Source Name	Status	Use Type
				Johns River		Institutional
22454	OCW3B	unknown	4514	Saint Johns River	Removed	Commercial/Industrial/ Institutional
22455	OCW3A	unknown	4514	Saint Johns River	Removed	Commercial/Industrial/ Institutional
22456	LF3B	27	10000	Saint Johns River	Active	Commercial/Industrial/ Institutional
22457	LF3A	27	10000	Saint Johns River	Active	Commercial/Industrial/ Institutional
497528	SW-1	unknown	400	Saint Johns River	Proposed	Commercial/Industrial/ Institutional
497537	SW-2	unknown	400	Saint Johns River	Proposed	Commercial/Industrial/ Institutional

Conditions

1. With advance notice to the permittee, District staff with proper identification shall have permission to enter, inspect, observe, collect samples, and take measurements of permitted facilities to determine compliance with the permit conditions and permitted plans and specifications. The permittee shall either accompany District staff onto the property or make provision for access onto the property.

2. Nothing in this permit should be construed to limit the authority of the St. Johns River Water Management District to declare a water shortage and issue orders pursuant to Chapter 373, F.S. In the event of a declared water shortage, the permittee must adhere to the water shortage restrictions, as specified by the District. The permittee is advised that during a water shortage, reports shall be submitted as required by District rule or order.

3. Prior to the construction, modification or abandonment of a well, the permittee must obtain a water well permit from the St. Johns River Water Management District or the appropriate local government pursuant to Chapter 40C-3, F.A.C. Construction, modification, or abandonment of a well will require modification of the consumptive use permit when such construction, modification, or abandonment is other than that specified and described on the consumptive use permit application form.

4. Leaking or inoperative well casings, valves, or controls must be repaired or replaced as required to eliminate the leak or make the system fully operational.

5. The permittee's consumptive use of water as authorized by this permit shall not interfere with legal uses of water existing at the time of permit application. If interference occurs, the District shall revoke the permit, in whole or in part, to curtail or abate the interference, unless the interference associated with the permittee's consumptive use of water is mitigated by the permittee pursuant to a District-approved plan.

6. The permittee's consumptive use of water as authorized by this permit shall not have significant adverse hydrologic impacts to off-site land uses existing at the time of permit application. If significant adverse hydrologic impacts occur, the District shall revoke the permit, in whole or in part, to curtail or abate the adverse impacts, unless the impacts associated with the permittee's consumptive use of water are mitigated by the permittee pursuant to a District-approved plan.

7. The permittee shall notify the District in writing within 30 days of any sale, transfer, or conveyance of ownership or any other loss of permitted legal control of the Project and/or related facilities from which the permitted consumptive use is made. Where permittee's control of the land subject to the permit was demonstrated through a lease, the permittee must either submit documentation showing that it continues to have legal control or transfer control of the permitted system/project to the new landowner or new lessee. All transfers of ownership are subject to the requirements of Rule 40C-1.612, F.A.C. Alternatively, the permittee may surrender the consumptive use permit to the District, thereby relinquishing the right to conduct any activities under the permit.

8. A District-issued identification tag shall be prominently displayed at each withdrawal site by permanently affixing such tag to the pump, headgate, valve, or other withdrawal facility as provided by Rule 40C-2.401, F.A.C. The permittee shall notify the District in the event that a replacement tag is needed.

9. The permittee's consumptive use of water as authorized by this permit shall not adversely impact wetlands, lakes, rivers, or springs. If adverse impacts occur, the District shall revoke the permit, in whole or in part, to curtail or abate the adverse impacts, unless the impacts associated with the permittee's consumptive use of water are mitigated by the permittee pursuant to a District-approved plan.

10. The permittee's consumptive use of water as authorized by this permit shall not reduce a flow or level below any minimum flow or level established by the District or the Department of Environmental Protection pursuant to Section 373.042 and 373.0421, F.S. If the permittee's use of water causes or contributes to such a reduction, then the District shall revoke the permit, in whole or in part, unless the permittee implements all provisions applicable to the permittee's use in a District-approved recovery or prevention strategy.

11. The permittee's consumptive use of water as authorized by the permit shall not cause or contribute to significant saline water intrusion. If significant saline water intrusion occurs, the District shall revoke the permit, in whole or in part, to curtail or abate the saline water intrusion, unless the saline water intrusion associated with the permittee's consumptive use of water is mitigated by the permittee pursuant to a District-approved plan.

12. The permittee's consumptive use of water as authorized by the permit shall not cause or contribute to flood damage. If the permittee's consumptive use causes or contributes to flood damage, the District shall revoke the permit, in whole or in part, to curtail or abate the flood damage, unless the flood damage associated with the permittee's consumptive use of water is mitigated by the permittee pursuant to a District-approved plan.

13. All consumptive uses authorized by this permit shall be implemented as conditioned by this permit, including any documents incorporated by reference in a permit condition. The District may revoke this permit, in whole or in part, or take enforcement action, pursuant to Section 373.136 or 373.243, F.S., unless a permit modification has been obtained to address the noncompliance. The permittee shall immediately notify the District in writing of any previously submitted information that is later discovered to be inaccurate.

14. The permittee shall use the lowest quality water source, such as reclaimed water, surface/storm water, or alternative water supply, to supply the needs of the project when deemed feasible pursuant to District rules and applicable state law.

15. This permit does not convey to the permittee any property rights or privileges other than those specified herein, nor relieve the permittee from complying with any applicable local government, state, or federal law, rule, or ordinance.

16. A permittee may seek modification of any term of an unexpired permit. The permittee is advised that Section 373.239, F.S., and Rule 40C-2.331, F.A.C., are applicable to permit modifications.

17. This permit will expire on July 13, 2041.

18. Maximum annual groundwater withdrawals for commercial / industrial use must not exceed 103.7 million gallons (0.284 million gallons per day (mgd) average) in 2021 through 2023.

19. The maximum annual surface water use must not exceed 5,475.00 million gallons (15.00 million gallons per day (mgd) average) for commercial / industrial use in 2021 through 2041. Annual surface water withdrawals, including amounts for circulation through the existing intake structure, must not exceed 50,445 million gallons (138.21 mgd average).

20. The permittee must operate wells 3 (station ID 17680) and 4 (station ID 17681) for backup use only beginning no later than August 1, 2023. Both of these wells must be properly abandoned by August 1, 2024.

21. Pumps SW-1 (Station ID 497528) and SW-2 (Station ID 497537), CW3A (Station ID 2956), CW3B (Station ID 2957), LF3A (Station ID 22457), and LF3B (Station ID 22456), and wells 3 (Station ID17680) and 4 (Station ID 17681) must be equipped with totalizing flow meters or an alternative method for measuring flow must be implemented. Withdrawals from the ground water wells are measured utilizing a totalizing in-line flow meter. The totalizing flow meter must maintain a 95% accuracy, be verifiable and be installed according to manufacturer specifications.

    The permittee has elected to implement an alternative method for pumps SW-1 (Station ID 497528), SW-2 (Station ID 497537), CW3A (Station ID 2956), CW3B (Station ID 2957), LF3A (Station ID 22457), and LF3B (Station ID 22456) where the pump on/off times are electronically recorded. The flow is determined using the running times of the pumps and the appropriate pump log curves and pump rate as a basis for calculating the quantity of water withdrawn from the St Johns River. The permittee may not alter the approved alternative method without prior written approval from the District. The method must maintain 90% accuracy and be verifiable.

22. Total withdrawal, from pumps SW-1 (Station ID 497528) and SW-2 (Station ID 497537), CW3A (Station ID 2956), CW3B (Station ID 2957), LF3A (Station ID 22457), and LF3B (Station ID 22456) and well numbers 3 (Station ID 17680) and 4 (Station ID 17681), as listed on the application, must be recorded continuously, totaled monthly, and reported to the District every six months for the duration of the permit using District Form No. EN-50. The reporting dates each year will be as follows:

    <u>Reporting Period</u>   <u>Report Due Date</u>

January-June	July 31
July-December	January 31

23. The permittee must implement the Water Conservation Plan submitted to the District on June 8, 2020, in accordance with the schedule contained therein.

24. The permittee must maintain all flowmeters and alternative methods for measuring flow. In case of failure or breakdown of any meter, the District must be notified in writing within 5 days of its discovery. A defective meter must be repaired or replaced within 30 days of its discovery.

25. In order to ensure that the volume of water withdrawn and recorded by the permittee is accurate to within +/- 5% of actual flow (+/- 10% of flow when using an alternative method), the meter accuracy or flow rate from each withdrawal point must be validated once every 10 years and recorded on either the Flow Meter Accuracy Report Form (EN-51) or Alternative Method Flow Verification Report Form (whichever form is applicable). The validation documents must be provided to the District upon request.

26. The permittee shall submit, to the District, a compliance report pursuant to subsection 373.236(4), F.S., every 10 years during the term of the permit. The permittee shall submit the report by July 13, 2031. The report shall contain sufficient information to demonstrate that the permittee's use of water will continue, for the remaining duration of the permit, to meet the conditions for permit issuance set forth in the District rules that existed at the time the permit was issued for 20 years by the District. At a minimum, the compliance report must:
    - meet the submittal requirements of section 4.2 of the Applicant's Handbook: Consumptive Uses of Water, August 29, 2018;
    - include documentation verifying that the source is capable of supplying the needs authorized by this permit without causing harm to water resources;
    - include documentation verifying that the permittee is implementing all feasible water conservation measures;
    - document that the lowest acceptable quality water source, including reclaimed water or surface water (which includes storm water), must be utilized for each consumptive use;
    - ensure that all monitoring requirements are met;
    - and include information documenting that the projected allocation is needed.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE FINAL TRUE-UP AMOUNT FOR THE PERIOD

FORM: 42-1A

JANUARY 2020 THROUGH DECEMBER 2020

	2020
1. Over/(Under) Recovery for the Current Period (Form 42-2A, Line 5)	$5,523,105
2. Interest Provision (Form 42-2A, Line 6)	$44,650
3. Prior Period Adjustment (Form 42-2A, Line 10) [a]	($56,859)
4. Total	$5,510,896
5. Actual/Estimated Over/(Under) Recovery for the Same Period [b]	$7,661,744
6. Net True-Up for the period Over/(Under) Recovery	($2,150,848)

[a] Prior period adjustments for Scholz Ash Pond, Smith Ash Pond, and Crist Landfill.
[b] Approved in Order No. PSC-2021-0115-PAA-EI issued March 22,2021.

Note: Totals may not add due to rounding

FORM: 42-2A

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE FINAL TRUE-UP AMOUNT FOR THE PERIOD

JANUARY 2020 THROUGH DECEMBER 2020

	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Total
1. ECRC Revenues (net of Revenue Taxes)	$13,111,890	$11,731,758	$12,146,163	$12,671,424	$14,987,254	$16,732,287	$19,212,594	$19,145,495	$15,919,180	$14,232,052	$12,407,576	$14,158,763	$176,456,436
2. True-up Provision [(a)]	$542,141	$542,142	$542,142	$542,142	$542,142	$542,142	$542,142	$542,142	$542,142	$542,142	$542,142	$542,142	$6,505,703
3. ECRC Revenues Applicable to Period (Lines 1 + 2)	$13,654,031	$12,273,900	$12,688,305	$13,213,566	$15,529,396	$17,274,429	$19,754,736	$19,687,637	$16,461,322	$14,774,194	$12,949,718	$14,700,905	$182,962,139
4. Jurisdictional ECRC Costs													
a. O&M Activities (Form 42-5A-2, Line 6)	$2,068,656	$1,461,904	$2,487,378	$1,283,000	$3,198,728	($925,618)	$2,434,820	$2,242,194	$1,076,935	$1,583,566	$3,140,787	$1,801,539	$21,853,888
b. Capital Investment Projects (Form 42-7A-2, Line 6)	$13,146,097	$13,265,775	$13,256,688	$13,249,879	$13,237,770	$13,289,346	$13,452,154	$13,477,717	$13,497,353	$12,525,384	$11,559,737	$11,627,248	$155,585,146
c. Total Jurisdictional ECRC Costs	$15,214,753	$14,727,678	$15,744,066	$14,532,879	$16,436,497	$12,363,727	$15,886,974	$15,719,911	$14,574,288	$14,108,950	$14,700,524	$13,428,787	$177,439,034
5. Over/(Under) Recovery (Line 3 - Line 4c)	($1,560,721)	($2,453,779)	($3,055,760)	($1,319,313)	($907,102)	$4,910,701	$3,867,762	$3,967,727	$1,887,034	$665,244	($1,750,806)	$1,272,117	$5,523,105
6. Interest Provision (Form 42-3A, Line 10)	$15,195	$11,670	$8,593	$2,600	$64	$225	$640	$978	$1,217	$1,135	$1,229	$1,104	$44,650
7. Prior Periods True-Up to be (Collected)/Refunded	$6,505,703	$4,361,178	$1,376,927	($2,212,381)	($4,071,237)	($5,520,416)	($1,151,632)	$2,174,628	$5,601,190	$6,947,300	$7,071,538	$4,779,819	$6,505,703
a. Deferred True-Up (Form 42-1A, Line 7) [(b)]	$5,891,843	$5,891,843	$5,891,843	$5,891,843	$5,891,843	$5,891,843	$5,891,843	$5,891,843	$5,891,843	$5,891,843	$5,891,843	$5,891,843	
8. True-Up Collected /(Refunded) (See Line 2)	($542,141)	($542,142)	($542,142)	($542,142)	($542,142)	($542,142)	($542,142)	($542,142)	($542,142)	($542,142)	($542,142)	($542,142)	($6,505,703)
9. End of Period True-Up (Lines 5+6+7+7a+8)	$10,309,879	$7,268,770	$3,679,461	$1,820,606	$371,426	$4,740,210	$8,066,471	$11,493,033	$12,839,142	$12,963,380	$10,671,661	$11,402,739	$5,567,755
10. Adjustments to Period Total True-Up Including Interest	($56,859)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($56,859)
11. End of Period Total Net True-Up (Lines 9+10)	$10,253,020	$7,268,770	$3,679,461	$1,820,606	$371,426	$4,740,210	$8,066,471	$11,493,033	$12,839,142	$12,963,380	$10,671,661	$11,402,739	$5,510,896

[(a)] As approved in Order No. PSC-2018-0594-FOF-EI issued December 20, 2018.
[(b)] From FPL's 2019 Final True-up filed on April 1,2020.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
INTEREST CALCULATION

FORM: 42-3A

JANUARY 2020 THROUGH DECEMBER 2020

	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Total
1. Beginning True-Up Amount (Form 42-2A, Lines 7 + 7a + 10)	$12,340,687	$10,253,020	$7,268,770	$3,679,461	$1,820,606	$371,426	$4,740,210	$8,066,471	$11,493,033	$12,839,142	$12,963,380	$10,671,661	N/A
2. Ending True-Up Amount before Interest (Line 1 + Form 42-2A Lines 5 + 8)	$10,237,825	$7,257,100	$3,670,868	$1,818,006	$371,362	$4,739,986	$8,065,830	$11,492,056	$12,837,925	$12,962,244	$10,670,432	$11,401,637	N/A
3. Total of Beginning & Ending True-Up (Lines 1 + 2)	$22,578,512	$17,510,120	$10,939,638	$5,497,468	$2,191,969	$5,111,412	$12,806,041	$19,558,527	$24,330,958	$25,801,387	$23,633,813	$22,073,298	N/A
4. Average True-Up Amount (Line 3 x 1/2)	$11,289,256	$8,755,060	$5,469,819	$2,748,734	$1,095,984	$2,555,706	$6,403,020	$9,779,263	$12,165,479	$12,900,693	$11,816,906	$11,036,649	N/A
5. Interest Rate (First Day of Reporting Month)	1.59000%	1.64000%	1.56000%	2.21000%	0.06000%	0.08000%	0.13000%	0.11000%	0.13000%	0.11000%	0.10000%	0.15000%	N/A
6. Interest Rate (First Day of Subsequent Month)	1.64000%	1.56000%	2.21000%	0.06000%	0.08000%	0.13000%	0.11000%	0.13000%	0.11000%	0.10000%	0.15000%	0.09000%	N/A
7. Total of Beginning & Ending Interest Rates (Lines 5 + 6)	3.23000%	3.20000%	3.77000%	2.27000%	0.14000%	0.21000%	0.24000%	0.24000%	0.24000%	0.21000%	0.25000%	0.24000%	N/A
8. Average Interest Rate (Line 7 x 1/2)	1.61500%	1.60000%	1.88500%	1.13500%	0.07000%	0.10500%	0.12000%	0.12000%	0.12000%	0.10500%	0.12500%	0.12000%	N/A
9. Monthly Average Interest Rate (Line 8 x 1/12)	0.13458%	0.13333%	0.15708%	0.09458%	0.00583%	0.00875%	0.01000%	0.01000%	0.01000%	0.00875%	0.01042%	0.01000%	N/A
10. Interest Provision for the Month (Line 4 x Line 9)	$15,195	$11,670	$8,593	$2,600	$64	$225	$640	$978	$1,217	$1,135	$1,229	$1,104	$44,650

FORM 42-4A

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE FINAL TRUE-UP AMOUNT FOR THE PERIOD

JANUARY 2020 THROUGH DECEMBER 2020
VARIANCE REPORT OF O&M ACTIVITIES

O&M PROJECT	ECRC - 2020 Final True Up [(a)]	ECRC - 2020 Actual Estimated [(b)]	$ Dif ECRC 2020 Actual Estimated (c)	% Dif ECRC Actual Estimated (d)
2 - Air Emission Fees	$233,074	$270,737	($37,662)	(13.9%)
3 - Title V	$172,210	$217,024	($44,814)	(20.6%)
4 - Asbestos Fees	($183)	$1,000	($1,184)	(118.3%)
5 - Emission Monitoring	$686,024	$688,542	($2,518)	(0.4%)
6 - General Water Quality	$743,388	$1,257,915	($514,527)	(40.9%)
7 - Groundwater Contamination Investigation	$2,293,893	$2,091,013	$202,879	9.7%
8 - State NPDES Administration	$50,252	$49,516	$736	1.5%
10 - Env Auditing/Assessment	$2,242	$2,588	($346)	(13.4%)
11 - General Solid & Hazardous Waste	$729,228	$957,980	($228,752)	(23.9%)
12 - Above Ground Storage Tanks	$179,586	$196,679	($17,093)	(8.7%)
19 - FDEP NOx Reduction Agreement	$256,529	$227,320	$29,209	12.8%
20 - Air Quality Compliance Program	$15,350,929	$16,998,777	($1,647,848)	(9.7%)
22 - Crist Water Conservation	$111,448	$208,487	($97,038)	(46.5%)
23 - Coal Combustion Residuals	$1,093,607	$1,000,844	$92,763	9.3%
24 - Smith Water Conservation	$32,558	$36,806	($4,248)	(11.5%)
27 - Emission Allowances	$64,436	$33,325	$31,112	93.4%
Total	$21,999,222	$24,238,551	($2,239,329)	(9.2%)

[(a)] The 12-Month Totals on Form 42-5A
[(b)] Approved in Order No. PSC-2020-0433-FOF-EI issued November 13, 2020.
[(c)] Column (2) - Column (3)
[(d)] Column (4) / Column (3)

ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE FINAL TRUE-UP AMOUNT FOR THE PERIOD

JANUARY 2020 THROUGH DECEMBER 2020
O&M ACTIVITIES

Project #	O&M Project/Strata	Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	12-Month Total
2	Air Emission Fees - Intermediate	$0	$0	$16,229	$0	$0	$0	$0	$0	$0	$0	$0	$0	$16,229
2	Air Emission Fees - Base	$3,475	($6,635)	$116,465	$16,883	$11,153	($34,291)	$2,941	$115,469	($20,980)	$2,973	$1,554	$3,317	$212,326
2	Air Emission Fees - Peaking	$0	$0	$4,519	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,519
3	Title V - Base	$5,831	$11,821	$8,043	$6,602	$7,456	$6,645	$7,236	$6,552	$5,364	$6,801	$6,533	$7,638	$86,523
3	Title V - Peaking	$2,975	$6,031	$4,103	$3,368	$3,804	$3,391	$3,692	$3,343	$2,737	$3,470	$3,333	$3,897	$44,145
3	Title V - Intermediate	$3,418	$4,039	$6,123	$6,561	$2,547	$3,853	$2,846	$2,238	$1,832	$2,323	$2,232	$3,529	$41,543
4	Asbestos Fees - Base	$1,536	$500	$0	$0	$733	($2,269)	$0	$0	$0	$0	$0	$0	$500
4	Asbestos Fees - Intermediate	$793	$500	$51,500	($18)	$0	($52,061)	$0	$0	$0	$12,336	($12,336)	($1,397)	($683)
5	Emission Monitoring - Base	$21,815	$24,974	$27,587	$39,998	$66,701	$23,965	$31,770	$40,286	$40,935	$35,036	$28,071	$66,304	$447,442
5	Emission Monitoring - Peaking	$1,948	$4,735	$3,736	$7,820	$8,456	$11,186	$10,262	($885)	$986	$2,280	$4,536	$19,951	$75,011
5	Emission Monitoring - Intermediate	$22,319	$10,986	$9,917	$12,651	$13,477	$7,490	$6,871	$7,743	$13,196	$16,826	$21,321	$20,774	$163,571
6	General Water Quality - Base	($26,860)	$54,769	$82,652	$21,468	$14,814	$10,285	$63,430	$57,540	$31,503	$66,517	$39,067	$76,277	$491,464
6	General Water Quality - Peaking	($27,224)	$8,809	$17,655	$7,223	($7,357)	($18,161)	$13,232	$7,758	$6,220	$8,492	$9,207	$15,426	$41,281
6	General Water Quality - Intermediate	($18,229)	$11,057	$15,966	$9,923	($12,426)	$39,383	$12,999	$9,336	$8,177	$12,761	$18,766	$15,858	$123,571
6	General Water Quality - Transmission	$5,124	$5,454	$4,837	$8,579	$5,057	$5,314	$4,823	$4,351	$14,785	$14,799	$8,162	$5,788	$87,073
7	Groundwater Contamination Investigation - Base	($34,003)	($34,003)	($34,003)	($34,003)	($34,003)	($34,003)	($34,003)	($34,003)	($34,003)	($34,003)	($34,003)	($34,003)	($408,036)
7	Groundwater Contamination Investigation - Distribution	$252,118	$206,649	$220,887	$279,735	$428,483	$567,080	$193,251	$99,834	$100,151	$216,830	$29,666	$68,172	$2,662,857
7	Groundwater Contamination Investigation - Transmission	$1,820	$2,915	$2,255	$1,530	$3,633	$1,719	$1,109	($642)	$716	$20,775	$1,448	$1,795	$39,072
8	State NPDES Administration - Base	$592	$1,222	$1,114	$5,157	$7,065	($7,022)	$0	$0	$766	$1,434	($3,260)	$23,000	$30,068
8	State NPDES Administration - Intermediate	$2,428	$1,897	$15,614	$9,089	$9,261	($30,789)	$4,160	$7,118	$0	$1,593	($12,870)	$12,684	$20,184
10	Environmental Auditing/Assessment - Base	($2,653)	$0	$0	$0	$15,390	$0	$1,027	$0	$0	($7,207)	$0	($5,347)	$1,211
10	Environmental Auditing/Assessment - Intermediate	($906)	$0	$0	$0	$5,258	$0	$351	$0	$0	($2,462)	$0	($1,827)	$414
10	Environmental Auditing/Assessment - Peaking	($1,353)	$0	$0	$0	$7,852	$0	$524	$0	$0	($3,677)	$0	($2,728)	$618
11	General Solid & Hazardous Waste - Base	($7,400)	($7,400)	($7,400)	($7,400)	($7,400)	($7,400)	($7,400)	($7,400)	($7,400)	($7,400)	($7,400)	($7,400)	($88,800)
11	General Solid & Hazardous Waste - Base	$81,494	$60,632	($48,690)	$17,350	$17,246	$24,337	$10,317	$8,580	$8,964	$19,737	$13,186	$23,057	$236,209
11	General Solid & Hazardous Waste - Peaking	$3,134	$5,740	$3,840	$2,124	$2,661	$5,303	$2,741	$3,529	$2,439	$2,923	$5,439	$4,458	$44,331
11	General Solid & Hazardous Waste - Intermediate	$2,045	$3,442	$2,356	$1,155	$1,677	$3,499	$1,705	$2,363	$1,358	$1,559	$3,244	$2,587	$26,989
11	General Solid & Hazardous Waste - Distribution	$36,884	$41,303	$65,615	$47,956	$37,937	$20,759	$40,460	$18,521	$14,054	$39,057	$23,793	$124,161	$510,498
12	Above Ground Storage Tanks - Base	$3,482	$6,699	$4,158	$15,270	$4,224	$4,622	$4,588	$7,428	$4,116	$4,331	$3,950	$7,294	$70,160
12	Above Ground Storage Tanks - Peaking	$1,776	$2,741	$2,121	$2,121	$2,155	$2,358	$2,238	$2,046	$2,100	$2,210	$2,015	$2,177	$26,060
12	Above Ground Storage Tanks - Distribution	$0	$50	$0	$0	$0	$675	$0	$5,705	$0	$0	$20,500	$23,466	$50,396
12	Above Ground Storage Tanks - Intermediate	$1,189	$1,835	$1,870	$1,420	$5,787	$12,048	$1,756	$1,370	$1,406	$1,480	$1,349	$1,458	$32,969
19	FDEP NOx Reduction Agreement - Base	$78,137	$5,298	($23,349)	$3,073	$3,309	$8,947	$19,335	$33,463	$39,361	$0	$0	$88,955	$256,529
20	Air Quality Compliance Program - Base	$1,147,480	$731,048	$1,745,060	$728,491	$1,120,104	$405,263	$1,904,251	$1,771,091	$1,044,236	$1,082,671	$2,615,666	$1,055,568	$15,350,929
22	Crist Water Conservation - Base	$0	$0	$0	$0	$16,509	$3,624	$37,185	$8,266	$30,914	$5,838	$571	$8,543	$111,448
23	Coal Combustion Residuals - Base	$382,624	$257,018	$87,958	($14,590)	$1,264,646	($1,677,380)	$44,862	$27,437	$15,961	$12,377	$12,816	$77,343	$491,072
23	Coal Combustion Residuals - Intermediate	$84,295	$47,771	$95,068	$80,521	$190,725	($231,080)	$72,982	$32,076	($264,361)	$44,264	$348,070	$102,203	$602,535
24	Smith Water Conservation - Intermediate	$4,254	$2,466	$2,933	($1,373)	$120	$3,316	$1,856	$9,598	$0	$4,070	$2,637	$2,681	$32,558
27	Emission Allowances - Base	$37,829	$1,109	$0	$18,946	($2)	($2)	($13,676)	($2)	$11,678	$4,306	($2)	$4,247	$64,428
27	Emission Allowances - Intermediate	($3)	$0	$0	$44	($1)	($1)	($35)	($1)	($1)	$20	($1)	($1)	$21
27	Emission Allowances - Peaking	($4)	$0	$0	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($12)
	Total	$2,072,181	$1,475,475	$2,506,739	$1,297,675	$3,217,047	($919,397)	$2,449,684	$2,250,108	$1,077,209	$1,595,340	$3,157,260	$1,819,902	$21,999,222

ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE FINAL TRUE-UP AMOUNT FOR THE PERIOD

JANUARY 2020 THROUGH DECEMBER 2020
O&M ACTIVITIES

			Jurisdictionalization		Classification		
Project Num	O&M Project/Strata	12-Month Total	Juris Factor	Juris 12 Month Amount	12 CP Demand	Energy	NCP Demand
2	Air Emission Fees - Intermediate	$16,229	97.5922%	$15,839		$15,839	
2	Air Emission Fees - Base	$212,326	100.0000%	$212,326		$212,326	
2	Air Emission Fees - Peaking	$4,519	76.0860%	$3,438		$3,438	
3	Title V - Base	$86,523	100.0000%	$86,523		$86,523	
3	Title V - Peaking	$44,145	76.0860%	$33,588		$33,588	
3	Title V - Intermediate	$41,543	97.5922%	$40,543		$40,543	
4	Asbestos Fees - Base	$500	100.0000%	$500	$500		
4	Asbestos Fees - Intermediate	($683)	97.5922%	($667)	($667)		
5	Emission Monitoring - Base	$447,442	100.0000%	$447,442		$447,442	
5	Emission Monitoring - Peaking	$75,011	97.0000%	$72,761		$72,761	
5	Emission Monitoring - Intermediate	$163,571	97.5922%	$159,632		$159,632	
6	General Water Quality - Base	$491,464	100.0000%	$491,464	$491,464		
6	General Water Quality - Peaking	$41,281	97.0000%	$40,043	$40,043		
6	General Water Quality - Intermediate	$123,571	97.5922%	$120,595	$120,595		
6	General Water Quality - Transmission	$87,073	97.2343%	$84,665	$84,665		
7	Groundwater Contamination Investigation - Base	($408,036)	100.0000%	($408,036)	($408,036)		
7	Groundwater Contamination Investigation - Distribution	$2,662,857	98.1419%	$2,613,379			$2,613,379
7	Groundwater Contamination Investigation - Transmission	$39,072	97.2343%	$37,991	$37,991		
8	State NPDES Administration - Base	$30,068	100.0000%	$30,068	$30,068		
8	State NPDES Administration - Intermediate	$20,184	97.5922%	$19,698	$19,698		
10	Environmental Auditing/Assessment - Base	$1,211	100.0000%	$1,211	$1,211		
10	Environmental Auditing/Assessment - Intermediate	$414	97.5922%	$404	$404		
10	Environmental Auditing/Assessment - Peaking	$618	97.0000%	$599	$599		
11	General Solid & Hazardous Waste - Base	($88,800)	100.0000%	($88,800)	($88,800)		
11	General Solid & Hazardous Waste - Base	$236,209	100.0000%	$236,209	$236,209		
11	General Solid & Hazardous Waste - Peaking	$44,331	97.0000%	$43,002	$43,002		
11	General Solid & Hazardous Waste - Intermediate	$26,989	97.5922%	$26,339	$26,339		
11	General Solid & Hazardous Waste - Distribution	$510,498	98.1419%	$501,013			$501,013
12	Above Ground Storage Tanks - Base	$70,160	100.0000%	$70,160	$70,160		
12	Above Ground Storage Tanks - Peaking	$26,060	97.0000%	$25,278	$25,278		
12	Above Ground Storage Tanks - Distribution	$50,396	98.1419%	$49,460			$49,460
12	Above Ground Storage Tanks - Intermediate	$32,969	97.5922%	$32,176	$32,176		
19	FDEP NOx Reduction Agreement - Base	$256,529	100.0000%	$256,529		$256,529	
20	Air Quality Compliance Program - Base	$15,350,929	100.0000%	$15,350,929		$15,350,929	
22	Crist Water Conservation - Base	$111,448	100.0000%	$111,448	$111,448		
23	Coal Combustion Residuals - Base	$491,072	100.0000%	$491,072	$491,072		
23	Coal Combustion Residuals - Intermediate	$602,535	97.5922%	$588,027	$588,027		
24	Smith Water Conservation - Intermediate	$32,558	97.5922%	$31,774	$31,774		
27	Emission Allowances - Base	$64,428	100.0000%	$64,428		$64,428	
27	Emission Allowances - Intermediate	$21	97.5922%	$20		$20	
27	Emission Allowances - Peaking	($12)	76.0860%	($10)		($10)	
	Total	$21,999,222		$21,893,060	$1,985,219	$16,743,989	$3,163,852

JANUARY 2020 THROUGH DECEMBER 2020
O&M ACTIVITIES

RAD - ECRC - 42 - 5A - 2	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
2. Total of O&M Activities	$2,072,181	$1,475,475	$2,506,739	$1,297,675	$3,217,047	($919,397)	$2,449,684	$2,250,108	$1,077,209	$1,595,340	$3,157,260	$1,819,902	$21,999,222
3. Recoverable Costs Jurisdictionalized on Energy - Base	$1,294,567	$767,616	$1,873,806	$813,993	$1,208,720	$410,528	$1,951,857	$1,966,859	$1,120,593	$1,131,787	$2,651,822	$1,226,029	$16,418,177
Recoverable Costs Jurisdictionalized on Energy - Intermediate	$25,735	$15,024	$32,269	$19,256	$16,023	$11,343	$9,682	$9,980	$15,028	$19,170	$23,553	$24,302	$221,364
Recoverable Costs Jurisdictionalized on Energy - Peaking	$4,919	$10,766	$12,358	$11,187	$12,259	$14,576	$13,953	$2,457	$3,722	$5,750	$7,869	$23,846	$123,662
Recoverable Costs Jurisdictionalized on 12 CP Demand - Trans.	$6,943	$8,370	$7,092	$10,109	$8,690	$7,032	$5,932	$3,708	$15,501	$35,574	$9,609	$7,583	$126,145
Recoverable Costs Jurisdictionalized on 12 CP Demand - Base	$398,812	$339,437	$85,788	$3,251	$1,299,223	($1,685,206)	$120,005	$67,849	$50,821	$61,626	$24,927	$168,762	$935,296
Recoverable Costs Jurisdictionalized on 12 CP Demand - Interm.	$75,869	$68,969	$185,308	$100,718	$200,402	($255,684)	$95,808	$61,860	($253,419)	$75,600	$348,859	$134,247	$838,536
Recoverable Costs Jurisdictionalized on 12 CP Demand - Peaking	($23,667)	$17,290	$23,617	$11,469	$5,311	($10,500)	$18,736	$13,334	$10,759	$9,947	$16,661	$19,333	$112,290
Recoverable Costs Jurisdictionalized on NCP Demand - Dist.	$289,003	$248,003	$286,501	$327,691	$466,419	$588,514	$233,711	$124,061	$114,205	$255,887	$73,960	$215,799	$3,223,752
4. Retail Production Energy Jurisdictional Factor - Base	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	
Retail Production Energy Jurisdictional Factor - Intermediate	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	
Retail Production Energy Jurisdictional Factor - Peaking	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	
Retail Distribution Demand Jurisdictional Factor	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	
Retail Transmission Demand Jurisdictional Factor	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	
Retail Production Demand Jurisdictional Factor - Base	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	
Retail Production Demand Jurisdictional Factor - Intermediate	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	
Retail Production Demand Jurisdictional Factor - Peaking	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	
5. Jurisdictional Recoverable Costs- Transmission	$6,751	$8,138	$6,896	$9,830	$8,450	$6,838	$5,768	$3,606	$15,072	$34,590	$9,343	$7,373	$122,656
Jurisdictional Recoverable Costs - Production - Base	$1,693,379	$1,107,053	$1,959,594	$817,244	$2,507,943	($1,274,678)	$2,071,862	$2,034,708	$1,171,414	$1,193,413	$2,676,749	$1,394,791	$17,353,473
Jurisdictional Recoverable Costs - Production - Intermediate	$99,158	$81,970	$212,338	$117,085	$211,214	($238,458)	$102,950	$70,111	($232,652)	$92,487	$363,445	$154,732	$1,034,380
Jurisdictional Recoverable Costs - Production - Peaking	($14,264)	$21,347	$27,372	$17,238	$13,368	$3,101	$24,872	$12,015	$11,018	$11,943	$18,664	$32,854	$179,527
Jurisdictional Recoverable Costs - Distribution	$283,633	$243,394	$281,178	$321,602	$457,753	$577,579	$229,368	$121,755	$112,083	$251,132	$72,585	$211,789	$3,163,852
6. Total Jurisdictional Recoverable Costs for O&M	$2,068,656	$1,461,904	$2,487,378	$1,283,000	$3,198,728	($925,618)	$2,434,820	$2,242,194	$1,076,935	$1,583,566	$3,140,787	$1,801,539	$21,853,888

FORM 42-6A

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE FINAL TRUE-UP AMOUNT FOR THE PERIOD

JANUARY 2020 THROUGH DECEMBER 2020
VARIANCE REPORT OF CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

Capital Project	ECRC - 2020 Final True Up [a]	Revised ECRC 2020 Actual Estimated [b]	$ Dif ECRC 2020 Actual Estimated [c]	% Dif ECRC 2020 Actual Estimated [d]
1 - Air Quality Assurance Testing	$17,141	$17,141	($0)	(0.0%)
2 - Crist 5, 6 & 7 Precipitator Projects	$3,510,505	$3,510,505	($0)	(0.0%)
3 - Crist 7 Flue Gas Conditioning	$104,389	$104,389	($0)	(0.0%)
4 - Low NOx Burners, Crist 6 & 7	$1,733,968	$1,733,968	($0)	(0.0%)
5 - CEMS - Plants Crist, & Daniel	$533,364	$533,364	($0)	(0.0%)
6 - Substation Contamination Remediation	$414,825	$415,526	($701)	(0.2%)
7 - Raw Water Well Flowmeters - Plants Crist & Smith	$12,688	$12,688	($0)	(0.0%)
8 - Crist Cooling Tower Cell	$37,035	$37,035	$0	0.0%
9 - Crist Dechlorination System	$23,178	$23,178	($0)	(0.0%)
10 - Crist Diesel Fuel Oil Remediation	$194	$194	$0	0.0%
11 - Crist Bulk Tanker Unload Sec Contain Struc	$4,429	$4,429	$0	0.0%
12 - Crist IWW Sampling System	$2,822	$2,822	($0)	(0.0%)
13 - Sodium Injection System	$18,642	$18,642	($0)	(0.0%)
14 - Smith Stormwater Collection System	$165,602	$165,602	($0)	(0.0%)
15 - Smith Waste Water Treatment Facility	$69,378	$69,378	$0	0.0%
16 - Daniel Ash Management Project	$1,243,496	$1,243,496	($0)	(0.0%)
17 - Smith Water Conservation	$2,300,367	$2,304,613	($4,246)	(0.2%)
19 - Crist FDEP Agreement for Ozone Attainment	$9,721,133	$9,722,929	($1,796)	(0.0%)
20 - SPCC Compliance	$74,023	$74,023	$0	0.0%
21 - Crist Common FTIR Monitor	($860)	($860)	$0	(0.0%)
22 - Precipitator Upgrades for CAM Compliance	$983,557	$983,557	$0	0.0%
24 - Crist Water Conservation	$1,683,450	$1,683,450	$0	0.0%
25 - Plant NPDES Permit Compliance Projects	$1,134,164	$1,112,903	$21,261	1.9%
26 - Air Quality Compliance Program	$119,600,030	$118,423,951	$1,176,079	1.0%
27 - General Water Quality	$381,883	$441,535	($59,652)	(13.5%)
28 - Coal Combustion Residual	$8,373,457	$9,160,660	($787,203)	(8.6%)
29 - Steam Electric Effluent Limitations Guidelines	$663,301	$669,659	($6,358)	(0.9%)
30 - 316(b) Cooling Water Intake Structure Regulation	$93,637	$114,654	($21,016)	(18.3%)
NOx Allowances	$522	$1,240	($719)	(57.9%)
SO2 Allowances	$437,921	$437,357	$563	0.1%
35 - Scherer/Flint Credit - Energy	($9,777)	($9,777)	$0	
36 - Scherer/Flint Credit - Demand	($117,327)	($117,327)	$0	
37 - Regulatory Asset Smith Units 1 & 2	$2,661,190	$2,661,190	$0	
Total	$155,872,328	$155,556,116	$316,212	0.2%

[a] The 12-Month Totals on Form 42-7A
[b] Approved in Order No. PSC-2021-0115-PAA-EI issued March 22,2021
[c] Column (2) - Column (3)
[d] Column (4) / Column (3)

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE FINAL TRUE UP AMOUNT

JANUARY 2020 THROUGH DECEMBER 2020
CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

Capital Project	Strata	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1-Air Quality Assurance Testing	Base	$1,458	$1,452	$1,446	$1,440	$1,435	$1,429	$1,428	$1,422	$1,417	$1,411	$1,405	$1,399	$17,141
2-Crist 5, 6 & 7 Precipitator Projects	Base	$312,196	$311,550	$310,903	$310,256	$309,609	$308,962	$310,764	$310,109	$309,455	$267,057	$224,904	$224,738	$3,510,505
3-Crist 7 Flue Gas Conditioning	Base	$8,645	$8,645	$8,645	$8,645	$8,645	$8,645	$8,753	$8,753	$8,753	$8,753	$8,753	$8,753	$104,389
4-Low NOx Burners, Crist 6 & 7	Base	$145,362	$145,095	$144,828	$144,561	$144,294	$144,027	$144,976	$144,706	$144,435	$144,165	$143,895	$143,624	$1,733,968
5-CEMS - Plants Crist & Daniel	Base	$44,755	$44,668	$44,580	$44,492	$44,404	$44,317	$44,580	$44,491	$44,403	$44,314	$44,225	$44,136	$533,364
6-Substation Contamination Remediation	Distribution	$30,027	$29,988	$29,948	$29,195	$28,445	$28,413	$28,668	$30,175	$31,672	$31,622	$31,572	$31,546	$361,271
6-Substation Contamination Remediation	Transmission	$3,910	$4,019	$4,020	$3,942	$3,950	$4,304	$4,720	$4,827	$4,932	$4,950	$4,978	$5,003	$53,554
7-Raw Water Flowmeters Plants Crist & Smith	Base	$794	$791	$788	$785	$783	$780	$780	$777	$774	$771	$769	$766	$9,359
7-Raw Water Flowmeters Plants Crist & Smith	Intermediate	$276	$276	$276	$276	$276	$276	$279	$279	$279	$279	$279	$279	$3,329
8-Crist Cooling Tower Cell	Base	$3,067	$3,067	$3,067	$3,067	$3,067	$3,067	$3,105	$3,105	$3,105	$3,105	$3,105	$3,105	$37,035
9-Crist Dechlorination System	Base	$1,968	$1,960	$1,953	$1,946	$1,939	$1,931	$1,932	$1,925	$1,917	$1,910	$1,902	$1,895	$23,178
10-Crist Diesel Fuel Oil Remediation	Base	($112)	($113)	($113)	($114)	($9)	$95	$95	$94	$94	$93	$93	$93	$194
11-Crist Bulk Tanker Second Containment	Base	$414	$412	$410	$409	$407	$405	$403	$402	$400	$313	$227	$226	$4,429
12-Crist IWW Sampling System	Base	$241	$240	$239	$238	$237	$236	$235	$234	$233	$231	$230	$229	$2,822
13-Sodium Injection System	Base	$1,775	$1,769	$1,764	$1,758	$1,753	$1,748	$1,752	$1,746	$1,741	$1,262	$787	$787	$18,642
14-Smith Stormwater Collection System	Intermediate	$14,126	$14,064	$14,001	$13,939	$13,877	$13,814	$13,788	$13,725	$13,662	$13,599	$13,535	$13,472	$165,602
15-Smith Waste Water Treatment Facility	Intermediate	$5,141	$3,829	$2,551	$2,593	$5,753	$7,068	$7,110	$7,096	$7,081	$7,066	$7,052	$7,037	$69,378
16-Daniel Ash Management Project	Base	$104,530	$104,314	$104,099	$103,883	$103,668	$103,453	$103,803	$103,585	$103,367	$103,149	$102,931	$102,713	$1,243,496
17-Smith Water Conservation	Intermediate	$192,306	$191,838	$190,786	$188,724	$191,108	$192,259	$193,167	$192,793	$192,388	$192,001	$191,640	$191,358	$2,300,367
19-Crist Ozone Attainment	Base	$875,753	$874,289	$871,950	$869,611	$867,271	$864,074	$866,561	$863,879	$861,198	$725,437	$590,585	$590,524	$9,721,133
20-SPCC Compliance	Base	$5,939	$5,922	$5,904	$5,886	$5,869	$5,851	$5,868	$5,850	$5,832	$5,814	$5,796	$5,778	$70,309
20-SPCC Compliance	General	$200	$199	$198	$197	$196	$196	$195	$194	$193	$192	$191	$191	$2,344
20-SPCC Compliance	Intermediate	$116	$115	$115	$115	$114	$114	$114	$114	$114	$113	$113	$113	$1,370
21-Crist Common FTIR Monitor	Base	($191)	($191)	($191)	($191)	($96)	$0	$0	$0	$0	$0	$0	$0	($860)
22-Precipitator Upgrades - CAM Compliance	Base	$92,733	$92,466	$92,199	$91,932	$91,665	$91,398	$91,690	$91,420	$91,149	$67,787	$44,560	$44,560	$983,557
24-Crist Water Conservation	Base	$145,606	$143,689	$141,277	$140,404	$143,336	$144,484	$145,068	$144,679	$144,290	$135,880	$127,516	$127,221	$1,683,450
25-Plant NPDES Permit Compliance	Base	$41,345	$40,092	$43,948	$48,016	$54,938	$51,884	$63,879	$74,142	$73,948	$73,755	$73,561	$73,516	$713,025
25-Plant NPDES Permit Compliance	Intermediate	$35,443	$35,357	$35,271	$35,186	$35,100	$35,014	$35,179	$35,092	$35,005	$34,918	$34,831	$34,744	$421,140
26-Air Quality Compliance Program	Base	$10,319,672	$10,297,050	$10,281,856	$10,262,022	$10,241,628	$10,219,181	$10,272,287	$10,256,943	$10,240,952	$9,437,570	$8,637,110	$8,630,175	$119,096,444
26-Air Quality Compliance Program	Peaking	$1,967	$1,960	$1,953	$1,946	$1,939	$1,932	$1,934	$1,927	$1,920	$1,913	$1,906	$2,127	$23,427
26-Air Quality Compliance Program	Transmission	$40,308	$40,225	$40,143	$40,061	$39,979	$39,896	$40,133	$40,050	$39,966	$39,883	$39,800	$39,716	$480,159
27-General Water Quality	Base	$19,048	$30,857	$31,200	$31,245	$31,361	$31,972	$33,183	$33,348	$33,066	$33,129	$33,489	$39,985	$381,883
28-Coal Combustion Residuals	Base	$180,489	$185,822	$185,438	$189,319	$172,763	$233,281	$297,885	$312,243	$333,802	$367,647	$396,130	$435,009	$3,289,828
28-Coal Combustion Residuals	Intermediate	$348,189	$355,021	$365,478	$378,195	$390,929	$407,661	$429,594	$448,900	$466,549	$478,067	$495,642	$519,401	$5,083,629
29-Steam Electric Effluent Limitations	Base	$54,385	$53,369	$53,320	$53,318	$55,143	$56,255	$56,694	$56,642	$56,683	$55,483	$55,414	$56,594	$663,301
30-316b Cooling Water Intake Structure	Intermediate	$2,109	$3,284	$4,955	$6,083	$6,651	$6,712	$6,847	$8,500	$10,181	$10,297	$10,460	$17,558	$93,637
Regulatory Asset Smith Units 1 & 2	Intermediate	$224,899	$224,215	$223,531	$222,848	$222,164	$221,480	$222,073	$221,381	$220,688	$219,996	$219,304	$218,612	$2,661,190
NOx Allowances	Base	$47	$46	$47	$46	$46	$46	$45	$43	$43	$40	$37	$37	$522
SO_2 Allowances	Base	$36,329	$36,313	$36,309	$36,254	$36,200	$36,200	$36,694	$36,735	$36,735	$36,727	$36,719	$36,706	$437,921
Scherer/Flint Credit - Energy	Base	($9,777)												($9,777)
Scherer/Flint Credit - Demand	Base	($117,327)												($117,327)
		$13,168,161	$13,287,967	$13,279,091	$13,272,527	$13,260,834	$13,312,859	$13,476,262	$13,502,327	$13,522,425	$12,550,701	$11,585,448	$11,653,726	$155,872,328

[a] Each project's Total Recoverable Costs on Form 42-8A, Line 9.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE FINAL TRUE UP AMOUNT

JANUARY 2020 THROUGH DECEMBER 2020
CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
		Monthly Data	Jurisdictionalization		Method of Classification		
Capital Project	Strata	Twelve Month Total	Jurisdictional Factor	Juris Twelve Month Amount	Energy	12 CP Demand	NCP Demand
1-Air Quality Assurance Testing	Base	$17,141	100.0000%	$17,141	$1,319	$15,823	$0
2-Crist 5, 6 & 7 Precipitator Projects	Base	$3,510,505	100.0000%	$3,510,505	$270,039	$3,240,466	$0
3-Crist 7 Flue Gas Conditioning	Base	$104,389	100.0000%	$104,389	$8,030	$96,359	$0
4-Low NOx Burners, Crist 6 & 7	Base	$1,733,968	100.0000%	$1,733,968	$133,382	$1,600,586	$0
5-CEMS - Plants Crist & Daniel	Base	$533,364	100.0000%	$533,364	$41,028	$492,336	$0
6-Substation Contamination Remediation	Distribution	$361,271	98.1419%	$354,559	$0	$0	$354,559
6-Substation Contamination Remediation	Transmission	$53,554	97.2343%	$52,073	$4,006	$48,067	$0
7-Raw Water Flowmeters Plants Crist & Smith	Base	$9,359	100.0000%	$9,359	$720	$8,639	$0
7-Raw Water Flowmeters Plants Crist & Smith	Intermediate	$3,329	97.5922%	$3,249	$250	$2,999	$0
8-Crist Cooling Tower Cell	Base	$37,035	100.0000%	$37,035	$2,849	$34,186	$0
9-Crist Dechlorination System	Base	$23,178	100.0000%	$23,178	$1,783	$21,395	$0
10-Crist Diesel Fuel Oil Remediation	Base	$194	100.0000%	$194	$15	$179	$0
11-Crist Bulk Tanker Second Containment	Base	$4,429	100.0000%	$4,429	$341	$4,088	$0
12-Crist IWW Sampling System	Base	$2,822	100.0000%	$2,822	$217	$2,605	$0
13-Sodium Injection System	Base	$18,642	100.0000%	$18,642	$1,434	$17,208	$0
14-Smith Stormwater Collection System	Intermediate	$165,602	97.5922%	$161,615	$12,432	$149,183	$0
15-Smith Waste Water Treatment Facility	Intermediate	$69,378	97.5922%	$67,707	$5,208	$62,499	$0
16-Daniel Ash Management Project	Base	$1,243,496	100.0000%	$1,243,496	$95,654	$1,147,843	$0
17-Smith Water Conservation	Intermediate	$2,300,367	97.5922%	$2,244,980	$172,691	$2,072,289	$0
19-Crist Ozone Attainment	Base	$9,721,133	100.0000%	$9,721,133	$747,779	$8,973,353	$0
20-SPCC Compliance	Base	$70,309	100.0000%	$70,309	$5,408	$64,901	$0
20-SPCC Compliance	General	$2,344	96.9888%	$2,273	$175	$2,099	$0
20-SPCC Compliance	Intermediate	$1,370	97.5922%	$1,337	$103	$1,234	$0
21-Crist Common FTIR Monitor	Base	($860)	100.0000%	($860)	($66)	($794)	$0
22-Precipitator Upgrades - CAM Compliance	Base	$983,557	100.0000%	$983,557	$75,658	$907,899	$0
24-Crist Water Conservation	Base	$1,683,450	100.0000%	$1,683,450	$129,496	$1,553,953	$0
25-Plant NPDES Permit Compliance	Base	$713,025	100.0000%	$713,025	$54,848	$658,177	$0
25-Plant NPDES Permit Compliance	Intermediate	$421,140	97.5922%	$410,999	$31,615	$379,384	$0
26-Air Quality Compliance Program	Base	$119,096,444	100.0000%	$119,096,444	$9,161,265	$109,935,179	$0
26-Air Quality Compliance Program	Peaking	$23,427	76.0860%	$17,825	$1,371	$16,453	$0
26-Air Quality Compliance Program	Transmission	$480,159	97.2343%	$466,879	$35,914	$430,965	$0
27-General Water Quality	Base	$381,883	100.0000%	$381,883	$29,376	$352,507	$0
28-Coal Combustion Residuals	Base	$3,289,828	100.0000%	$3,289,828	$253,064	$3,036,764	$0
28-Coal Combustion Residuals	Intermediate	$5,083,629	97.5922%	$4,961,227	$381,633	$4,579,594	$0
29-Steam Electric Effluent Limitations	Base	$663,301	100.0000%	$663,301	$51,023	$612,277	$0
30-316b Cooling Water Intake Structure	Intermediate	$93,637	97.5922%	$91,383	$7,029	$84,353	$0
Regulatory Asset Smith Units 1 & 2	Intermediate	$2,661,190	97.5922%	$2,597,115	$199,778	$2,397,337	$0
NOx Allowances	Base	$522	100.0000%	$522	$40	$481	$0
SO2 Allowances	Base	$437,921	100.0000%	$437,921	$33,686	$404,234	$0
Scherer/Flint Credit - Energy	Base	($9,777)	100.0000%	($9,777)	($9,777)	$0	$0
Scherer/Flint Credit - Demand	Base	($117,327)	100.0000%	($117,327)	$0	($117,327)	$0
		$155,872,328		$155,585,151	$11,940,815	$143,289,777	$354,559

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE FINAL TRUE UP AMOUNT

FORM: 42-7A-2

JANUARY 2020 THROUGH DECEMBER 2020
CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
2. Total of Capital Investment Projects	$13,168,161	$13,287,967	$13,279,091	$13,272,527	$13,260,834	$13,312,859	$13,476,262	$13,502,327	$13,522,425	$12,550,701	$11,585,448	$11,653,726	$155,872,328
3. Recoverable Costs Jurisdictionalized on 12 CP Demand - Trans.	$44,218	$44,244	$44,163	$44,003	$43,928	$44,200	$44,853	$44,877	$44,898	$44,833	$44,778	$44,719	$533,713
Recoverable Costs Jurisdictionalized on 12 CP Demand - Base	$12,269,145	$12,383,576	$12,365,864	$12,349,229	$12,320,353	$12,353,718	$12,492,460	$12,497,275	$12,497,793	$11,515,804	$10,534,143	$10,572,569	$144,151,930
Recoverable Costs Jurisdictionalized on 12 CP Demand - Inter.	$822,604	$827,999	$836,964	$847,958	$865,972	$884,399	$908,152	$927,880	$945,948	$956,337	$972,857	$1,002,574	$10,799,642
Recoverable Costs Jurisdicitionalized on 12 CP Demand - Peaking	$1,967	$1,960	$1,953	$1,946	$1,939	$1,932	$1,934	$1,927	$1,920	$1,913	$1,906	$2,127	$23,427
Recoverable Costs Jurisdicitionalized on 12 CP Demand - General	$200	$199	$198	$197	$196	$196	$195	$194	$193	$192	$191	$191	$2,344
Recoverable Costs Jurisdictionalized on NCP Demand - Dist.	$30,027	$29,988	$29,948	$29,195	$28,445	$28,413	$28,668	$30,175	$31,672	$31,622	$31,572	$31,546	$361,271
4. Retail Transmission Demand Jurisdictional Factor	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	
Retail Production Demand Jurisdictional Factor - Base	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	
Retail Production Demand Jurisdictional Factor - Intermediate	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	
Retail Production Demand Jurisdictional Factor - Peaking	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	
Retail Production Demand Jurisdictional Factor - General	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%	
Retail Distribution Demand Jurisdictional Factor	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	
5. Jurisdictional Recoverable Costs - Transmission	$42,995	$43,021	$42,941	$42,786	$42,713	$42,978	$43,612	$43,636	$43,657	$43,593	$43,539	$43,482	$518,952
Jurisdictional Recoverable Costs - Production - Base	$12,269,145	$12,383,576	$12,365,864	$12,349,229	$12,320,353	$12,353,718	$12,492,460	$12,497,274	$12,497,793	$11,515,804	$10,534,143	$10,572,569	$144,151,929
Jurisdictional Recoverable Costs - Production - Intermediate	$802,797	$808,063	$816,812	$827,540	$845,121	$863,104	$886,286	$905,538	$923,171	$933,310	$949,433	$978,434	$10,539,610
Jurisdictional Recoverable Costs - Production - Peaking	$1,497	$1,491	$1,486	$1,481	$1,476	$1,470	$1,472	$1,466	$1,461	$1,456	$1,450	$1,619	$17,824
Jurisdictional Recoverable Costs - General	$194	$193	$192	$191	$191	$190	$189	$188	$187	$187	$186	$185	$2,274
Jurisdictional Recoverable Costs - Distribution	$29,469	$29,431	$29,392	$28,652	$27,917	$27,885	$28,135	$29,614	$31,084	$31,035	$30,986	$30,960	$354,559
6. Total Jurisdictional Recoverable Costs for Capital	$13,146,097	$13,265,775	$13,256,688	$13,249,879	$13,237,770	$13,289,346	$13,452,154	$13,477,717	$13,497,353	$12,525,384	$11,559,737	$11,627,248	$155,585,146

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2020 THROUGH DECEMBER 2020

401-Air Quality Assurance Testing - Base

	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1	Investments														
a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	83,954	83,954	83,954	83,954	83,954	83,954	83,954	83,954	83,954	83,954	83,954	83,954	83,954	
3	Less: Accumulated Depreciation (C)	(3,998)	(4,997)	(5,997)	(6,996)	(7,996)	(8,995)	(9,995)	(10,994)	(11,993)	(12,993)	(13,992)	(14,992)	(15,991)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	79,956	78,957	77,957	76,958	75,958	74,959	73,959	72,960	71,960	70,961	69,962	68,962	67,963	
6	Average Net Investment		79,456	78,457	77,457	76,458	75,459	74,459	73,460	72,460	71,461	70,461	69,462	68,462	
7	Return on Average Net Investment														
a	Equity Component (D)		366	361	357	352	347	343	352	347	342	337	333	328	4,165
b	Debt Component		92	91	90	89	88	87	77	76	75	74	73	72	983
8	Investment Expenses														
a	Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Amortization (F)		999	999	999	999	999	999	999	999	999	999	999	999	11,993
c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		1,458	1,452	1,446	1,440	1,435	1,429	1,428	1,422	1,417	1,411	1,405	1,399	17,141

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2020 THROUGH DECEMBER 2020

402-Crist 5, 6 & 7 Precipitator Projects - Base

Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1 Investments														
a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c Retirements		0	0	0	0	0	0	0	0	0	(25,118,763)	0	0	(25,118,763)
d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2 Plant-in-Service/Depreciation Base (B)	33,657,087	33,657,087	33,657,087	33,657,087	33,657,087	33,657,087	33,657,087	33,657,087	33,657,087	33,657,087	8,538,323	8,538,323	8,538,323	
3 Less: Accumulated Depreciation (C)	1,086,225	974,034	861,844	749,654	637,464	525,273	413,083	300,893	188,702	76,512	25,124,950	25,096,489	25,068,028	
4 CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2+3+4) (A)	34,743,311	34,631,121	34,518,931	34,406,741	34,294,550	34,182,360	34,070,170	33,957,979	33,845,789	33,733,599	33,663,273	33,634,812	33,606,351	
6 Average Net Investment		34,687,216	34,575,026	34,462,836	34,350,645	34,238,455	34,126,265	34,014,075	33,901,884	33,789,694	33,698,436	33,649,043	33,620,582	
7 Return on Average Net Investment														
a Equity Component (D)		159,700	159,183	158,667	158,150	157,634	157,117	162,893	162,356	161,819	161,382	161,145	161,009	1,921,056
b Debt Component		40,307	40,176	40,046	39,915	39,785	39,655	35,681	35,563	35,445	35,350	35,298	35,268	452,489
8 Investment Expenses														
a Depreciation (E)		112,190	112,190	112,190	112,190	112,190	112,190	112,190	112,190	112,190	70,326	28,461	28,461	1,136,960
b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (H)		312,197	311,550	310,903	310,256	309,609	308,962	310,764	310,109	309,455	267,057	224,904	224,738	3,510,505

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2020 THROUGH DECEMBER 2020
403-Crist 7 Flue Gas Conditioning - Base

	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1	Investments														
a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	
6	Average Net Investment		1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	
7	Return on Average Net Investment														
a	Equity Component (D)		6,903	6,903	6,903	6,903	6,903	6,903	7,180	7,180	7,180	7,180	7,180	7,180	84,499
b	Debt Component		1,742	1,742	1,742	1,742	1,742	1,742	1,573	1,573	1,573	1,573	1,573	1,573	19,890
8	Investment Expenses														
a	Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		8,645	8,645	8,645	8,645	8,645	8,645	8,753	8,753	8,753	8,753	8,753	8,753	104,389

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2020 THROUGH DECEMBER 2020
404-Low NOx Burners, Crist 6 & 7 - Base

Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1 Investments														
a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2 Plant-in-Service/Depreciation Base (B)	13,527,932	13,527,932	13,527,932	13,527,932	13,527,932	13,527,932	13,527,932	13,527,932	13,527,932	13,527,932	13,527,932	13,527,932	13,527,932	
3 Less: Accumulated Depreciation (C)	3,671,263	3,624,938	3,578,612	3,532,287	3,485,962	3,439,636	3,393,311	3,346,986	3,300,660	3,254,335	3,208,010	3,161,684	3,115,359	
4 CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2+3+4) (A)	17,199,195	17,152,869	17,106,544	17,060,219	17,013,893	16,967,568	16,921,243	16,874,917	16,828,592	16,782,267	16,735,941	16,689,616	16,643,291	
6 Average Net Investment		17,176,032	17,129,707	17,083,381	17,037,056	16,990,731	16,944,405	16,898,080	16,851,755	16,805,429	16,759,104	16,712,779	16,666,453	
7 Return on Average Net Investment														
a Equity Component (D)		79,078	78,865	78,652	78,439	78,225	78,012	80,925	80,703	80,481	80,259	80,037	79,816	953,493
b Debt Component		19,959	19,905	19,851	19,797	19,743	19,689	17,726	17,677	17,629	17,580	17,532	17,483	224,571
8 Investment Expenses														
a Depreciation (E)		44,614	44,614	44,614	44,614	44,614	44,614	44,614	44,614	44,614	44,614	44,614	44,614	535,367
b Amortization (F)		1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	20,537
c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (H)		145,362	145,095	144,828	144,561	144,294	144,027	144,976	144,706	144,435	144,165	143,895	143,624	1,733,968

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8A

JANUARY 2020 THROUGH DECEMBER 2020

405-CEMS - Plants Crist & Daniel - Base

	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e PIS Adjustment		0	0	0	0	0	0	0	0	0	0	0	0	0
	f Accumulated Depreciation Adjustment		(29)	0	0	0	0	0	0	0	0	0	0	0	(29)
2	Plant-in-Service/Depreciation Base (B)	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	
3	Less: Accumulated Depreciation (C)	266,590	251,344	236,127	220,911	205,694	190,477	175,261	160,044	144,828	129,611	114,394	99,178	83,961	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	4,979,373	4,964,127	4,948,910	4,933,694	4,918,477	4,903,260	4,888,044	4,872,827	4,857,611	4,842,394	4,827,177	4,811,961	4,796,744	
6	Average Net Investment		4,971,750	4,956,519	4,941,302	4,926,085	4,910,869	4,895,652	4,880,435	4,865,219	4,850,002	4,834,786	4,819,569	4,804,352	
7	Return on Average Net Investment														
	a Equity Component (D)		22,890	22,820	22,750	22,680	22,610	22,540	23,372	23,300	23,227	23,154	23,081	23,008	275,430
	b Debt Component		5,777	5,759	5,742	5,724	5,706	5,689	5,120	5,104	5,088	5,072	5,056	5,040	64,876
8	Investment Expenses														
	a Depreciation (E)		15,217	15,217	15,217	15,217	15,217	15,217	15,217	15,217	15,217	15,217	15,217	15,217	182,599
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		872	872	872	872	872	872	872	872	872	872	872	872	10,460
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		44,755	44,668	44,580	44,492	44,404	44,317	44,580	44,491	44,403	44,314	44,225	44,136	533,364

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8A

JANUARY 2020 THROUGH DECEMBER 2020

406-Substation Contamination Remediation - Distribution

Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1 Investments														
a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	8,048	8,048
b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
e PIS Adjustment		0	0	0	0	0	0	0	0	0	0	0	0	0
f Accumulated Depreciation Adjustment		588	0	0	0	0	0	0	0	0	0	0	0	588
2 Plant-in-Service/Depreciation Base (B)	2,906,667	2,906,667	2,906,667	2,906,667	2,906,667	2,906,667	2,906,667	2,906,667	2,906,667	2,906,667	2,906,667	2,906,667	2,906,667	
3 Less: Accumulated Depreciation (C)	1,103,664	1,097,331	1,090,410	1,083,488	1,077,283	1,071,794	1,066,304	1,060,815	1,053,782	1,045,206	1,036,629	1,028,053	1,019,477	
4 CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	8,048	
5 Net Investment (Lines 2+3+4) (A)	4,010,332	4,003,998	3,997,077	3,990,156	3,983,950	3,978,461	3,972,971	3,967,482	3,960,449	3,951,873	3,943,297	3,934,720	3,934,192	
6 Average Net Investment		4,007,165	4,000,538	3,993,616	3,987,053	3,981,206	3,975,716	3,970,227	3,963,966	3,956,161	3,947,585	3,939,008	3,934,456	
7 Return on Average Net Investment														
a Equity Component (D)		18,449	18,418	18,387	18,356	18,329	18,304	19,013	18,983	18,946	18,905	18,864	18,842	223,798
b Debt Component		4,656	4,649	4,641	4,633	4,626	4,620	4,165	4,158	4,150	4,141	4,132	4,127	52,698
8 Investment Expenses														
a Depreciation (E)		6,921	6,921	6,921	6,205	5,489	5,489	5,489	7,033	8,576	8,576	8,576	8,576	84,775
b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (H)		30,027	29,988	29,948	29,195	28,445	28,413	28,668	30,175	31,672	31,622	31,572	31,546	361,271

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8A

JANUARY 2020 THROUGH DECEMBER 2020

406-Substation Contamination Remediation - Transmission

Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1 Investments														
a Expenditures/Additions		11,588	27,124	(25,982)	(554,252)	3,630	120,288	6,757	1,225,936	5,876	1,220	9,363	0	831,547
b Clearings to Plant		0	0	0	0	0	0	0	1,194,933	0	0	0	0	1,194,933
c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d Other		0	0	0	(554,252)	0	0	0	1,194,932	0	0	0	0	640,680
2 Plant-in-Service/Depreciation Base (B)	339,156	339,156	339,156	339,156	339,156	339,156	339,156	339,156	1,534,089	1,534,089	1,534,089	1,534,089	1,534,089	
3 Less: Accumulated Depreciation (C)	(44,792)	(45,273)	(45,753)	(46,233)	(46,714)	(47,194)	(47,675)	(48,155)	(48,636)	(49,116)	(49,597)	(50,077)	(50,558)	
4 CWIP - Non Interest Bearing	294,900	306,488	333,612	307,630	307,630	311,260	431,547	438,304	(725,625)	(719,750)	(718,529)	(709,166)	(709,166)	
5 Net Investment (Lines 2+3+4) (A)	589,264	600,371	627,015	600,553	600,072	603,221	723,028	729,305	759,828	765,223	765,963	774,846	774,366	
6 Average Net Investment		594,817	613,693	613,784	600,312	601,647	663,125	726,166	744,566	762,525	765,593	770,404	774,606	
7 Return on Average Net Investment														
a Equity Component (D)		2,739	2,825	2,826	2,764	2,770	3,053	3,478	3,566	3,652	3,666	3,689	3,710	38,737
b Debt Component		691	713	713	698	699	771	762	781	800	803	808	813	9,051
8 Investment Expenses														
a Depreciation (E)		480	480	480	480	480	480	480	480	480	480	480	480	5,766
b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (H)		3,910	4,019	4,020	3,942	3,950	4,304	4,720	4,827	4,932	4,950	4,978	5,003	53,554

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2020 THROUGH DECEMBER 2020
407-Raw Water Well Flowmeters Plants Crist & Smith - Base

	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	
3	Less: Accumulated Depreciation (C)	(98,670)	(99,170)	(99,670)	(100,170)	(100,670)	(101,170)	(101,669)	(102,169)	(102,669)	(103,169)	(103,669)	(104,169)	(104,668)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	51,279	50,779	50,280	49,780	49,280	48,780	48,280	47,780	47,281	46,781	46,281	45,781	45,281	
6	Average Net Investment		51,029	50,529	50,030	49,530	49,030	48,530	48,030	47,530	47,031	46,531	46,031	45,531	
7	Return on Average Net Investment														
	a Equity Component (D)		235	233	230	228	226	223	230	228	225	223	220	218	2,719
	b Debt Component		59	59	58	58	57	56	50	50	49	49	48	48	642
8	Investment Expenses														
	a Depreciation (E)		500	500	500	500	500	500	500	500	500	500	500	500	5,998
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		794	791	788	785	783	780	780	777	774	771	769	766	9,359

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

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GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2020 THROUGH DECEMBER 2020

407-Raw Water Well Flowmeters Plants Crist & Smith - Intermediate

	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1	Investments														
a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	
6	Average Net Investment		47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	
7	Return on Average Net Investment														
a	Equity Component (D)		220	220	220	220	220	220	229	229	229	229	229	229	2,695
b	Debt Component		56	56	56	56	56	56	50	50	50	50	50	50	634
8	Investment Expenses														
a	Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		276	276	276	276	276	276	279	279	279	279	279	279	3,329

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8A

JANUARY 2020 THROUGH DECEMBER 2020

408-Crist Cooling Tower Cell - Base

	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1	Investments														
a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	
6	Average Net Investment		531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	
7	Return on Average Net Investment														
a	Equity Component (D)		2,449	2,449	2,449	2,449	2,449	2,449	2,547	2,547	2,547	2,547	2,547	2,547	29,978
b	Debt Component		618	618	618	618	618	618	558	558	558	558	558	558	7,057
8	Investment Expenses														
a	Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		3,067	3,067	3,067	3,067	3,067	3,067	3,105	3,105	3,105	3,105	3,105	3,105	37,035

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8A

JANUARY 2020 THROUGH DECEMBER 2020

409-Crist Dechlorination System - Base

	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1	Investments														
a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	
3	Less: Accumulated Depreciation (C)	(258,869)	(260,138)	(261,407)	(262,676)	(263,945)	(265,214)	(266,483)	(267,752)	(269,021)	(270,290)	(271,559)	(272,828)	(274,097)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	121,828	120,559	119,290	118,021	116,752	115,483	114,214	112,945	111,676	110,407	109,138	107,869	106,600	
6	Average Net Investment		121,194	119,925	118,656	117,387	116,118	114,849	113,580	112,311	111,042	109,773	108,504	107,235	
7	Return on Average Net Investment														
a	Equity Component (D)		558	552	546	540	535	529	544	538	532	526	520	514	6,433
b	Debt Component		141	139	138	136	135	133	119	118	116	115	114	112	1,518
8	Investment Expenses														
a	Depreciation (E)		1,269	1,269	1,269	1,269	1,269	1,269	1,269	1,269	1,269	1,269	1,269	1,269	15,228
b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		1,968	1,960	1,953	1,946	1,939	1,931	1,932	1,925	1,917	1,910	1,902	1,895	23,178

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

FORM: 42-8A

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2020 THROUGH DECEMBER 2020

410-Crist Diesel Fuel Oil Remediation - Base

	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1	Investments														
a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
e	PIS Adjustment		0	0	0	0	0	0	0	0	0	0	0	0	0
f	Accumulated Depreciation Adjustment		0	0	0	0	36,282	0	0	0	0	0	0	0	36,282
2	Plant-in-Service/Depreciation Base (B)	20,968	20,968	20,968	20,968	20,968	20,968	20,968	20,968	20,968	20,968	20,968	20,968	20,968	
3	Less: Accumulated Depreciation (C)	(52,562)	(52,632)	(52,702)	(52,772)	(52,842)	(16,630)	(16,700)	(16,769)	(16,839)	(16,909)	(16,979)	(17,049)	(17,119)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	(31,595)	(31,665)	(31,734)	(31,804)	(31,874)	4,338	4,268	4,198	4,128	4,058	3,988	3,919	3,849	
6	Average Net Investment		(31,630)	(31,699)	(31,769)	(31,839)	(13,768)	4,303	4,233	4,163	4,093	4,023	3,954	3,884	
7	Return on Average Net Investment														
a	Equity Component (D)		(146)	(146)	(146)	(147)	(63)	20	20	20	20	19	19	19	(511)
b	Debt Component		(37)	(37)	(37)	(37)	(16)	5	4	4	4	4	4	4	(133)
8	Investment Expenses														
a	Depreciation (E)		70	70	70	70	70	70	70	70	70	70	70	70	839
b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		(112)	(113)	(113)	(114)	(9)	95	95	94	94	93	93	93	194

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

FORM: 42-8A

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2020 THROUGH DECEMBER 2020
411-Crist Bulk Tanker Unloading Second Containment - Base

Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1 Investments														
a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2 Plant-in-Service/Depreciation Base (B)	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	
3 Less: Accumulated Depreciation (C)	(88,134)	(88,473)	(88,811)	(89,149)	(89,488)	(89,826)	(90,164)	(90,503)	(90,841)	(91,179)	(91,433)	(91,602)	(91,771)	
4 CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2+3+4) (A)	13,361	13,022	12,684	12,346	12,007	11,669	11,331	10,992	10,654	10,316	10,062	9,893	9,724	
6 Average Net Investment		13,191	12,853	12,515	12,176	11,838	11,500	11,162	10,823	10,485	10,189	9,977	9,808	
7 Return on Average Net Investment														
a Equity Component (D)		61	59	58	56	55	53	53	52	50	49	48	47	640
b Debt Component		15	15	15	14	14	13	12	11	11	11	10	10	152
8 Investment Expenses														
a Depreciation (E)		338	338	338	338	338	338	338	338	338	254	169	169	3,637
b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (H)		414	412	410	409	407	405	403	402	400	313	227	226	4,429

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8A

JANUARY 2020 THROUGH DECEMBER 2020

412-Crist IWW Sampling System - Base

	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1	Investments														
a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	
3	Less: Accumulated Depreciation (C)	(52,023)	(52,222)	(52,420)	(52,619)	(52,817)	(53,015)	(53,214)	(53,412)	(53,611)	(53,809)	(54,008)	(54,206)	(54,405)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	7,520	7,321	7,123	6,924	6,726	6,527	6,329	6,130	5,932	5,733	5,535	5,336	5,138	
6	Average Net Investment		7,420	7,222	7,023	6,825	6,627	6,428	6,230	6,031	5,833	5,634	5,436	5,237	
7	Return on Average Net Investment														
a	Equity Component (D)		34	33	32	31	31	30	30	29	28	27	26	25	356
b	Debt Component		9	8	8	8	8	7	7	6	6	6	6	5	84
8	Investment Expenses														
a	Depreciation (E)		198	198	198	198	198	198	198	198	198	198	198	198	2,382
b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		241	240	239	238	237	236	235	234	233	231	230	229	2,822

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

FORM: 42-8A

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2020 THROUGH DECEMBER 2020

413-Sodium Injection System - Base

Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1 Investments														
a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2 Plant-in-Service/Depreciation Base (B)	284,622	284,622	284,622	284,622	284,622	284,622	284,622	284,622	284,622	284,622	284,622	284,622	284,622	
3 Less: Accumulated Depreciation (C)	(140,871)	(141,819)	(142,768)	(143,717)	(144,666)	(145,614)	(146,563)	(147,512)	(148,460)	(149,409)	(149,884)	(149,884)	(149,884)	
4 CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2+3+4) (A)	143,751	142,802	141,854	140,905	139,956	139,007	138,059	137,110	136,161	135,213	134,738	134,738	134,738	
6 Average Net Investment		143,277	142,328	141,379	140,431	139,482	138,533	137,584	136,636	135,687	134,975	134,738	134,738	
7 Return on Average Net Investment														
a Equity Component (D)		660	655	651	647	642	638	659	654	650	646	645	645	7,792
b Debt Component		166	165	164	163	162	161	144	143	142	142	141	141	1,837
8 Investment Expenses														
a Depreciation (E)		949	949	949	949	949	949	949	949	949	474	0	0	9,013
b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (H)		1,775	1,769	1,764	1,758	1,753	1,748	1,752	1,746	1,741	1,262	787	787	18,642

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8A

JANUARY 2020 THROUGH DECEMBER 2020

414-Smith Stormwater Collection System - Intermediate

Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1 Investments														
a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2 Plant-in-Service/Depreciation Base (B)	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	
3 Less: Accumulated Depreciation (C)	(2,186,795)	(2,197,622)	(2,208,449)	(2,219,277)	(2,230,104)	(2,240,931)	(2,251,758)	(2,262,585)	(2,273,412)	(2,284,240)	(2,295,067)	(2,305,894)	(2,316,721)	
4 CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2+3+4) (A)	577,583	566,756	555,929	545,102	534,275	523,448	512,621	501,793	490,966	480,139	469,312	458,485	447,658	
6 Average Net Investment		572,170	561,343	550,516	539,688	528,861	518,034	507,207	496,380	485,553	474,726	463,898	453,071	
7 Return on Average Net Investment														
a Equity Component (D)		2,634	2,584	2,535	2,485	2,435	2,385	2,429	2,377	2,325	2,273	2,222	2,170	28,854
b Debt Component		665	652	640	627	615	602	532	521	509	498	487	475	6,822
8 Investment Expenses														
a Depreciation (E)		10,827	10,827	10,827	10,827	10,827	10,827	10,827	10,827	10,827	10,827	10,827	10,827	129,926
b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (H)		14,126	14,064	14,001	13,939	13,877	13,814	13,788	13,725	13,662	13,599	13,535	13,472	165,602

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8A

JANUARY 2020 THROUGH DECEMBER 2020
415-Smith Waste Water Treatment Facility - Intermediate

Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1 Investments														
a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b Clearings to Plant		0	464,658	0	0	0	0	0	0	0	0	0	0	464,658
c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d Other		(7,018)	13,505	9,030	7,069	0	0	0	0	0	0	0	0	22,586
e PIS Adjustment		0	(464,658)	0	0	464,658	0	0	0	0	0	0	0	0
f Accumulated Depreciation Adjustment		4,596	0	0	0	(3,553)	0	0	0	0	0	0	0	1,043
2 Plant-in-Service/Depreciation Base (B)	178,962	178,962	178,962	178,962	178,962	643,620	643,620	643,620	643,620	643,620	643,620	643,620	643,620	
3 Less: Accumulated Depreciation (C)	128,007	124,884	137,688	146,017	152,385	146,311	143,790	141,269	138,748	136,228	133,707	131,186	128,665	
4 CWIP - Non Interest Bearing	464,658	464,658	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2+3+4) (A)	771,626	768,503	316,650	324,978	331,347	789,930	787,410	784,889	782,368	779,847	777,326	774,805	772,285	
6 Average Net Investment		770,065	542,576	320,814	328,163	560,639	788,670	786,149	783,628	781,108	778,587	776,066	773,545	
7 Return on Average Net Investment														
a Equity Component (D)		3,545	2,498	1,477	1,511	2,581	3,631	3,765	3,753	3,741	3,729	3,717	3,705	37,652
b Debt Component		895	630	373	381	651	916	825	822	819	817	814	811	8,756
8 Investment Expenses														
a Depreciation (E)		701	701	701	701	2,521	2,521	2,521	2,521	2,521	2,521	2,521	2,521	22,970
b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (H)		5,141	3,829	2,551	2,593	5,753	7,068	7,110	7,096	7,081	7,066	7,052	7,037	69,378

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8A

JANUARY 2020 THROUGH DECEMBER 2020

416-Daniel Ash Management Project - Base

Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1 Investments														
a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
e PIS Adjustment		0	0	0	0	0	0	0	0	0	0	0	0	0
f Accumulated Depreciation Adjustment		(6)	0	0	0	0	0	0	0	0	0	0	0	(6)
2 Plant-in-Service/Depreciation Base (B)	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	
3 Less: Accumulated Depreciation (C)	(6,833,021)	(6,870,382)	(6,907,737)	(6,945,092)	(6,982,446)	(7,019,801)	(7,057,156)	(7,094,511)	(7,131,866)	(7,169,221)	(7,206,576)	(7,243,931)	(7,281,286)	
4 CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2+3+4) (A)	8,106,540	8,069,179	8,031,824	7,994,470	7,957,115	7,919,760	7,882,405	7,845,050	7,807,695	7,770,340	7,732,985	7,695,630	7,658,275	
6 Average Net Investment		8,087,860	8,050,502	8,013,147	7,975,792	7,938,437	7,901,082	7,863,727	7,826,372	7,789,018	7,751,663	7,714,308	7,676,953	
7 Return on Average Net Investment														
a Equity Component (D)		37,237	37,065	36,893	36,721	36,549	36,377	37,659	37,480	37,302	37,123	36,944	36,765	444,112
b Debt Component		9,398	9,355	9,311	9,268	9,224	9,181	8,249	8,210	8,171	8,131	8,092	8,053	104,644
8 Investment Expenses														
a Depreciation (E)		37,355	37,355	37,355	37,355	37,355	37,355	37,355	37,355	37,355	37,355	37,355	37,355	448,259
b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d Property Taxes		20,540	20,540	20,540	20,540	20,540	20,540	20,540	20,540	20,540	20,540	20,540	20,540	246,481
e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (H)		104,530	104,314	104,099	103,883	103,668	103,453	103,803	103,585	103,367	103,149	102,931	102,713	1,243,496

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8A

JANUARY 2020 THROUGH DECEMBER 2020
417-Smith Water Conservation - Intermediate

Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1 Investments														
a Expenditures/Additions		(5,523)	4,464	5,916	1,049	16,483	(4,914)	24,570	16,234	14,378	21,902	23,770	48,510	166,841
b Clearings to Plant		0	6,087	214,648	351,783	0	0	0	0	0	0	0	0	572,518
c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
e PIS Adjustment		0	0	(214,648)	(346,443)	561,092	0	0	0	0	0	0	0	0
f Accumulated Depreciation Adjustment		(753)	0	0	0	(4,290)	0	0	0	0	0	0	0	(5,044)
2 Plant-in-Service/Depreciation Base (B)	21,018,243	21,018,243	21,024,330	21,024,330	21,029,670	21,590,761	21,590,761	21,590,761	21,590,761	21,590,761	21,590,761	21,590,761	21,590,761	
3 Less: Accumulated Depreciation (C)	(2,473,936)	(2,557,010)	(2,639,344)	(2,721,689)	(2,804,045)	(2,892,899)	(2,977,463)	(3,062,027)	(3,146,590)	(3,231,154)	(3,315,718)	(3,400,282)	(3,484,846)	
4 CWIP - Non Interest Bearing	574,610	569,087	567,464	358,732	7,998	24,481	19,568	44,138	60,372	74,750	96,653	120,422	168,933	
5 Net Investment (Lines 2+3+4) (A)	19,118,917	19,030,320	18,952,450	18,661,372	18,233,623	18,722,343	18,632,866	18,572,872	18,504,543	18,434,357	18,371,696	18,310,902	18,274,848	
6 Average Net Investment		19,074,619	18,991,385	18,806,911	18,447,497	18,477,983	18,677,605	18,602,869	18,538,708	18,469,450	18,403,026	18,341,299	18,292,875	
7 Return on Average Net Investment														
a Equity Component (D)		87,820	87,436	86,587	84,932	85,073	85,992	89,089	88,782	88,450	88,132	87,836	87,605	1,047,734
b Debt Component		22,165	22,068	21,854	21,436	21,471	21,703	19,514	19,447	19,374	19,305	19,240	19,189	246,767
8 Investment Expenses														
a Depreciation (E)		82,321	82,333	82,345	82,356	84,564	84,564	84,564	84,564	84,564	84,564	84,564	84,564	1,005,866
b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (H)		192,306	191,838	190,786	188,724	191,108	192,259	193,167	192,793	192,388	192,001	191,640	191,358	2,300,367

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8A

JANUARY 2020 THROUGH DECEMBER 2020

419-Crist FDEP Agreement for Ozone Attainment - Base

Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1 Investments														
a Expenditures/Additions		3,625	0	0	0	0	0	0	0	0	0	43,715	210,415	257,756
b Clearings to Plant		0	0	0	0	0	0	0	447,438	0	0	0	0	447,438
c Retirements		0	0	0	0	0	0	0	(636,130)	0	(80,272,078)	0	(35,137)	(80,943,345)
d Other		2,175	0	0	0	0	0	0	0	0	0	0	0	2,175
Accumulated Depreciation Adjustment		297,647	0	0	0	0	(297,647)	0	0	0	0	0	0	0
2 Plant-in-Service/Depreciation Base (B)	119,583,919	119,583,919	119,583,919	119,583,919	119,583,919	119,583,919	119,583,919	119,583,919	119,395,227	119,395,227	39,123,149	39,123,149	39,088,012	
3 Less: Accumulated Depreciation (C)	(38,453,274)	(38,559,142)	(38,964,831)	(39,370,521)	(39,776,211)	(40,181,901)	(40,885,238)	(41,290,927)	(41,060,173)	(41,465,234)	38,535,570	38,398,083	38,295,733	
4 CWIP - Non Interest Bearing	443,813	447,438	447,438	447,438	447,438	447,438	447,438	447,438	0	0	0	43,715	254,131	
5 Net Investment (Lines 2+3+4) (A)	81,574,458	81,472,215	81,066,526	80,660,836	80,255,146	79,849,456	79,146,119	78,740,430	78,335,054	77,929,993	77,658,719	77,564,948	77,637,876	
6 Average Net Investment		81,523,337	81,269,371	80,863,681	80,457,991	80,052,301	79,497,788	78,943,274	78,537,742	78,132,524	77,794,356	77,611,833	77,601,412	
7 Return on Average Net Investment														
a Equity Component (D)		375,333	374,164	372,296	370,429	368,561	366,008	378,059	376,117	374,177	372,557	371,683	371,633	4,471,018
b Debt Component		94,730	94,435	93,964	93,492	93,021	92,376	82,811	82,386	81,961	81,606	81,415	81,404	1,053,602
8 Investment Expenses														
a Depreciation (E)		395,861	395,861	395,861	395,861	395,861	395,861	395,861	395,547	395,232	261,445	127,658	127,658	4,078,568
b Amortization (F)		9,829	9,829	9,829	9,829	9,829	9,829	9,829	9,829	9,829	9,829	9,829	9,829	117,946
c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (H)		875,753	874,289	871,950	869,611	867,271	864,074	866,561	863,879	861,198	725,437	590,585	590,524	9,721,133

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8A

JANUARY 2020 THROUGH DECEMBER 2020

420-SPCC Compliance - Base

Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1 Investments														
a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2 Plant-in-Service/Depreciation Base (B)	919,836	919,836	919,836	919,836	919,836	919,836	919,836	919,836	919,836	919,836	919,836	919,836	919,836	
3 Less: Accumulated Depreciation (C)	(420,000)	(423,067)	(426,133)	(429,199)	(432,265)	(435,331)	(438,397)	(441,463)	(444,529)	(447,596)	(450,662)	(453,728)	(456,794)	
4 CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2+3+4) (A)	499,835	496,769	493,703	490,637	487,571	484,504	481,438	478,372	475,306	472,240	469,174	466,108	463,042	
6 Average Net Investment		498,302	495,236	492,170	489,104	486,038	482,971	479,905	476,839	473,773	470,707	467,641	464,575	
7 Return on Average Net Investment														
a Equity Component (D)		2,294	2,280	2,266	2,252	2,238	2,224	2,298	2,284	2,269	2,254	2,240	2,225	27,123
b Debt Component		579	575	572	568	565	561	503	500	497	494	491	487	6,393
8 Investment Expenses														
a Depreciation (E)		3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	36,793
b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (H)		5,939	5,922	5,904	5,886	5,869	5,851	5,868	5,850	5,832	5,814	5,796	5,778	70,309

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8A

JANUARY 2020 THROUGH DECEMBER 2020

420-SPCC Compliance - General

Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1 Investments														
a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2 Plant-in-Service/Depreciation Base (B)	13,195	13,195	13,195	13,195	13,195	13,195	13,195	13,195	13,195	13,195	13,195	13,195	13,195	
3 Less: Accumulated Depreciation (C)	(5,655)	(5,812)	(5,969)	(6,126)	(6,283)	(6,440)	(6,597)	(6,754)	(6,912)	(7,069)	(7,226)	(7,383)	(7,540)	
4 CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2+3+4) (A)	7,540	7,383	7,226	7,069	6,911	6,754	6,597	6,440	6,283	6,126	5,969	5,812	5,655	
6 Average Net Investment		7,461	7,304	7,147	6,990	6,833	6,676	6,519	6,362	6,205	6,048	5,890	5,733	
7 Return on Average Net Investment														
a Equity Component (D)		34	34	33	32	31	31	31	30	30	29	28	27	371
b Debt Component		9	8	8	8	8	8	7	7	7	6	6	6	88
8 Investment Expenses														
a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
b Amortization (F)		157	157	157	157	157	157	157	157	157	157	157	157	1,885
c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (H)		200	199	198	197	196	196	195	194	193	192	191	191	2,344

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

FORM: 42-8A

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2020 THROUGH DECEMBER 2020

420-SPCC Compliance - Intermediate

Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1 Investments														
a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2 Plant-in-Service/Depreciation Base (B)	14,895	14,895	14,895	14,895	14,895	14,895	14,895	14,895	14,895	14,895	14,895	14,895	14,895	
3 Less: Accumulated Depreciation (C)	(4,927)	(4,985)	(5,043)	(5,102)	(5,160)	(5,218)	(5,277)	(5,335)	(5,393)	(5,452)	(5,510)	(5,568)	(5,627)	
4 CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2+3+4) (A)	9,968	9,910	9,851	9,793	9,735	9,676	9,618	9,560	9,501	9,443	9,385	9,326	9,268	
6 Average Net Investment		9,939	9,881	9,822	9,764	9,706	9,647	9,589	9,531	9,472	9,414	9,356	9,297	
7 Return on Average Net Investment														
a Equity Component (D)		46	45	45	45	45	44	46	46	45	45	45	45	542
b Debt Component		12	11	11	11	11	11	10	10	10	10	10	10	128
8 Investment Expenses														
a Depreciation (E)		58	58	58	58	58	58	58	58	58	58	58	58	700
b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (H)		116	115	115	115	114	114	114	114	114	113	113	113	1,370

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2020 THROUGH DECEMBER 2020
421-Crist Common FTIR Monitor - Base

Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1 Investments														
a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
e PIS Adjustment		0	0	0	0	0	0	0	0	0	0	0	0	0
f Accumulated Depreciation Adjustment		0	0	0	0	33,156	0	0	0	0	0	0	0	33,156
2 Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3 Less: Accumulated Depreciation (C)	(33,156)	(33,156)	(33,156)	(33,156)	(33,156)	0	0	0	0	0	0	0	0	
4 CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2+3+4) (A)	(33,156)	(33,156)	(33,156)	(33,156)	(33,156)	0	0	0	0	0	0	0	0	
6 Average Net Investment		(33,156)	(33,156)	(33,156)	(33,156)	(16,578)	0	0	0	0	0	0	0	
7 Return on Average Net Investment														
a Equity Component (D)		(153)	(153)	(153)	(153)	(76)	0	0	0	0	0	0	0	(687)
b Debt Component		(39)	(39)	(39)	(39)	(19)	0	0	0	0	0	0	0	(173)
8 Investment Expenses														
a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (H)		(191)	(191)	(191)	(191)	(96)	0	0	0	0	0	0	0	(860)

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8A

JANUARY 2020 THROUGH DECEMBER 2020

422-Precipitator Upgrades for CAM Compliance - Base

	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1	Investments														
a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Retirements		0	0	0	0	0	0	0	0	0	(13,895,639)	0	0	(13,895,639)
d	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	13,895,639	13,895,639	13,895,639	13,895,639	13,895,639	13,895,639	13,895,639	13,895,639	13,895,639	13,895,639	0	0	0	
3	Less: Accumulated Depreciation (C)	(5,822,857)	(5,869,176)	(5,915,495)	(5,961,813)	(6,008,132)	(6,054,451)	(6,100,770)	(6,147,089)	(6,193,407)	(6,239,726)	7,632,753	7,632,753	7,632,753	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	8,072,782	8,026,463	7,980,144	7,933,825	7,887,506	7,841,188	7,794,869	7,748,550	7,702,231	7,655,912	7,632,753	7,632,753	7,632,753	
6	Average Net Investment		8,049,622	8,003,303	7,956,985	7,910,666	7,864,347	7,818,028	7,771,709	7,725,391	7,679,072	7,644,333	7,632,753	7,632,753	
7	Return on Average Net Investment														
a	Equity Component (D)		37,060	36,847	36,634	36,421	36,207	35,994	37,219	36,997	36,775	36,609	36,553	36,553	439,870
b	Debt Component		9,354	9,300	9,246	9,192	9,138	9,085	8,153	8,104	8,055	8,019	8,007	8,007	103,659
8	Investment Expenses														
a	Depreciation (E)		46,319	46,319	46,319	46,319	46,319	46,319	46,319	46,319	46,319	23,159	0	0	440,029
b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		92,733	92,466	92,199	91,932	91,665	91,398	91,690	91,420	91,149	67,787	44,560	44,560	983,557

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8A

JANUARY 2020 THROUGH DECEMBER 2020

424-Crist Water Conservation - Base

Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1 Investments														
a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b Clearings to Plant		0	533,264	0	0	0	0	0	0	0	0	0	0	533,264
c Retirements		0	0	(298,319)	0	0	0	0	0	0	(4,827,133)	0	0	(5,125,453)
d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
e PIS Adjustment		0	(533,264)	0	0	533,264	0	0	0	0	0	0	0	0
f Accumulated Depreciation Adjustment		0	0	0	0	(1,560)	0	0	0	0	0	0	0	(1,560)
2 Plant-in-Service/Depreciation Base (B)	19,748,717	19,748,717	19,748,717	19,450,398	19,450,398	19,983,662	19,983,662	19,983,662	19,983,662	19,983,662	15,156,528	15,156,528	15,156,528	
3 Less: Accumulated Depreciation (C)	(6,413,268)	(6,479,098)	(6,544,927)	(6,311,939)	(6,376,774)	(6,444,947)	(6,511,559)	(6,578,171)	(6,644,783)	(6,711,395)	(1,942,829)	(1,993,351)	(2,043,873)	
4 CWIP - Non Interest Bearing	533,264	533,264	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2+3+4) (A)	13,868,713	13,802,883	13,203,790	13,138,459	13,073,624	13,538,715	13,472,103	13,405,491	13,338,879	13,272,266	13,213,699	13,163,178	13,112,656	
6 Average Net Investment		13,835,798	13,503,337	13,171,125	13,106,041	13,306,170	13,505,409	13,438,797	13,372,185	13,305,573	13,242,983	13,188,439	13,137,917	
7 Return on Average Net Investment														
a Equity Component (D)		63,700	62,169	60,640	60,340	61,262	62,179	64,358	64,039	63,720	63,421	63,159	62,917	751,906
b Debt Component		16,077	15,691	15,305	15,229	15,462	15,693	14,097	14,027	13,958	13,892	13,835	13,782	177,048
8 Investment Expenses														
a Depreciation (E)		65,829	65,829	65,332	64,835	66,612	66,612	66,612	66,612	66,612	58,567	50,522	50,522	754,496
b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (H)		145,606	143,689	141,277	140,404	143,336	144,484	145,068	144,679	144,290	135,880	127,516	127,221	1,683,450

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2020 THROUGH DECEMBER 2020
425-Plant NPDES Permit Compliance Projects - Base

Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1 Investments														
a Expenditures/Additions		9,596	36,139	1,379,255	73,984	1,419,520	40,449	437,468	0	0	0	0	50,890	3,447,300
b Clearings to Plant		403,812	35,511	1,382	0	0	2,915,758	437,468	0	0	0	0	0	3,793,932
c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
e PIS Adjustment		(403,812)	(35,511)	(1,382)	0	440,705	(2,915,758)	2,915,758	0	0	0	0	0	0
f Accumulated Depreciation Adjustment		0	0	0	0	(289)	0	(21,488)	0	0	0	0	0	(21,778)
2 Plant-in-Service/Depreciation Base (B)	6,153,140	6,153,140	6,153,140	6,153,140	6,153,140	6,593,845	6,593,845	9,947,072	9,947,072	9,947,072	9,947,072	9,947,072	9,947,072	
3 Less: Accumulated Depreciation (C)	(2,729,897)	(2,750,408)	(2,770,918)	(2,791,429)	(2,811,939)	(2,834,208)	(2,856,187)	(2,910,103)	(2,943,260)	(2,976,417)	(3,009,574)	(3,042,731)	(3,075,888)	
4 CWIP - Non Interest Bearing	397,521	3,305	3,932	1,381,806	1,455,789	2,875,310	0	0	0	0	0	0	50,890	
5 Net Investment (Lines 2+3+4) (A)	3,820,764	3,406,038	3,386,154	4,743,517	4,796,991	6,634,947	3,737,658	7,036,968	7,003,811	6,970,655	6,937,498	6,904,341	6,922,073	
		3,305												
6 Average Net Investment		3,613,401	3,396,096	4,064,836	4,770,254	5,715,969	5,186,303	5,387,313	7,020,390	6,987,233	6,954,076	6,920,919	6,913,207	
7 Return on Average Net Investment														
a Equity Component (D)		16,636	15,636	18,715	21,962	26,316	23,878	25,800	33,621	33,462	33,303	33,144	33,107	315,580
b Debt Component		4,199	3,946	4,723	5,543	6,642	6,026	5,651	7,364	7,330	7,295	7,260	7,252	73,232
8 Investment Expenses														
a Depreciation (E)		20,510	20,510	20,510	20,510	21,979	21,979	32,428	33,157	33,157	33,157	33,157	33,157	324,213
b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (H)		41,345	40,092	43,948	48,016	54,938	51,884	63,879	74,142	73,948	73,755	73,561	73,516	713,025

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2020 THROUGH DECEMBER 2020
425-Plant NPDES Permit Compliance Projects - Intermediate

Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1 Investments														
a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
e PIS Adjustment		0	0	0	0	0	0	0	0	0	0	0	0	0
f Accumulated Depreciation Adjustment		0	0	0	0	0	0	0	0	0	0	0	0	0
2 Plant-in-Service/Depreciation Base (B)	3,798,266	3,798,266	3,798,266	3,798,266	3,798,266	3,798,266	3,798,266	3,798,266	3,798,266	3,798,266	3,798,266	3,798,266	3,798,266	
3 Less: Accumulated Depreciation (C)	(223,997)	(238,874)	(253,750)	(268,627)	(283,503)	(298,380)	(313,256)	(328,133)	(343,009)	(357,886)	(372,763)	(387,639)	(402,516)	
4 CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2+3+4) (A)	3,574,269	3,559,393	3,544,516	3,529,639	3,514,763	3,499,886	3,485,010	3,470,133	3,455,257	3,440,380	3,425,504	3,410,627	3,395,751	
6 Average Net Investment		3,566,831	3,551,954	3,537,078	3,522,201	3,507,325	3,492,448	3,477,572	3,462,695	3,447,819	3,432,942	3,418,065	3,403,189	
7 Return on Average Net Investment														
a Equity Component (D)		16,422	16,353	16,285	16,216	16,148	16,079	16,654	16,583	16,512	16,440	16,369	16,298	196,359
b Debt Component		4,145	4,127	4,110	4,093	4,076	4,058	3,648	3,632	3,617	3,601	3,586	3,570	46,262
8 Investment Expenses														
a Depreciation (E)		14,877	14,877	14,877	14,877	14,877	14,877	14,877	14,877	14,877	14,877	14,877	14,877	178,519
b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (H)		35,443	35,357	35,271	35,186	35,100	35,014	35,179	35,092	35,005	34,918	34,831	34,744	421,140

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8A

JANUARY 2020 THROUGH DECEMBER 2020
426-Air Quality Compliance Program - Base

Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1 Investments														
a Expenditures/Additions		258,626	377,494	316,304	39,535	549,804	(338,897)	1,689,676	897,280	1,345,418	1,073,124	822,540	(390,687)	6,640,218
b Clearings to Plant		34,419	11,845	806,381	682,034	21,349	1	1,502,602	11,709	64,798	0	27,486	527,637	3,690,262
c Retirements		(40,957)	0	(374,957)	(282,271)	(89,201)	0	(1,787,140)	0	(20,773)	(474,160,972)	0	0	(476,756,270)
d Other		(129,681)	47,578	(54,597)	31,487	27,284	(61,829)	74,933	4,794	22,370	111,395	(70,433)	10,772	14,074
e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
e PIS Adjustment		(1,319,038)	1,472,003	(289)	0	(152,604)	0		0	0	(51,482)	0	0	(51,410)
f Accumulated Depreciation Adjustment		(6,717)	(5,599)	0	0	1,720	0	0	0	0	0	0	798,805	788,210
2 Plant-in-Service/Depreciation Base (B)	1,336,985,358	1,335,659,782	1,337,143,630	1,337,574,765	1,337,974,528	1,337,754,072	1,337,754,073	1,337,469,536	1,337,481,245	1,337,525,271	863,312,817	863,340,303	863,867,940	
3 Less: Accumulated Depreciation (C)	(315,051,047)	(319,030,450)	(322,876,015)	(326,444,217)	(330,020,654)	(333,793,249)	(337,745,792)	(339,773,996)	(343,659,061)	(347,505,870)	123,666,825	121,286,893	119,785,377	
4 CWIP - Non Interest Bearing	2,015,378	2,239,585	2,605,234	2,115,157	1,472,658	2,001,113	1,662,215	1,849,289	2,734,860	4,015,480	5,088,604	5,883,658	5,492,970	
5 Net Investment (Lines 2+3+4) (A)	1,023,949,688	1,018,868,917	1,016,872,849	1,013,245,706	1,009,426,533	1,005,961,937	1,001,670,496	999,544,829	996,557,044	994,034,881	992,068,246	990,510,853	989,146,287	
6 Average Net Investment		1,021,409,303	1,017,870,883	1,015,059,277	1,011,336,119	1,007,694,235	1,003,816,216	1,000,607,662	998,050,936	995,295,962	993,051,564	991,289,550	989,828,570	
7 Return on Average Net Investment														
a Equity Component (D)		4,702,568	4,686,278	4,673,333	4,656,191	4,639,424	4,621,570	4,791,910	4,779,666	4,766,472	4,755,724	4,747,286	4,740,289	56,560,712
b Debt Component		1,186,878	1,182,766	1,179,499	1,175,173	1,170,941	1,166,434	1,049,637	1,046,955	1,044,065	1,041,711	1,039,863	1,038,330	13,322,253
8 Investment Expenses														
a Depreciation (E)		3,869,169	3,872,751	3,873,768	3,875,402	3,876,007	3,875,921	3,875,484	3,875,066	3,875,158	3,084,879	2,294,706	2,296,300	42,544,611
b Amortization (F)		14,793	14,793	14,793	14,793	14,793	14,793	14,793	14,793	14,793	14,793	14,793	14,793	177,520
c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d Property Taxes		546,264	540,462	540,462	540,462	540,462	540,462	540,462	540,462	540,462	540,462	540,462	540,462	6,491,350
e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (H)		10,319,672	10,297,050	10,281,856	10,262,022	10,241,628	10,219,181	10,272,287	10,256,943	10,240,952	9,437,570	8,637,110	8,630,175	119,096,444

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2020 THROUGH DECEMBER 2020

426-Air Quality Compliance Program - Peaking

Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1 Investments														
a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	78,196	78,196
b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2 Plant-in-Service/Depreciation Base (B)	229,742	229,742	229,742	229,742	229,742	229,742	229,742	229,742	229,742	229,742	229,742	229,742	229,742	
3 Less: Accumulated Depreciation (C)	(97,169)	(98,375)	(99,581)	(100,788)	(101,994)	(103,200)	(104,406)	(105,612)	(106,818)	(108,024)	(109,231)	(110,437)	(111,643)	
4 CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	78,196	
5 Net Investment (Lines 2+3+4) (A)	132,573	131,366	130,160	128,954	127,748	126,542	125,336	124,130	122,923	121,717	120,511	119,305	196,294	
6 Average Net Investment		131,970	130,763	129,557	128,351	127,145	125,939	124,733	123,527	122,320	121,114	119,908	157,800	
7 Return on Average Net Investment														
a Equity Component (D)		608	602	596	591	585	580	597	592	586	580	574	756	7,247
b Debt Component		153	152	151	149	148	146	131	130	128	127	126	166	1,706
8 Investment Expenses														
a Depreciation (E)		1,206	1,206	1,206	1,206	1,206	1,206	1,206	1,206	1,206	1,206	1,206	1,206	14,474
b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (H)		1,967	1,960	1,953	1,946	1,939	1,932	1,934	1,927	1,920	1,913	1,906	2,127	23,427

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2020 THROUGH DECEMBER 2020

426-Air Quality Compliance Program - Transmission

Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1 Investments														
a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2 Plant-in-Service/Depreciation Base (B)	6,079,391	6,079,391	6,079,391	6,079,391	6,079,391	6,079,391	6,079,391	6,079,391	6,079,391	6,079,391	6,079,391	6,079,391	6,079,391	
3 Less: Accumulated Depreciation (C)	(1,557,010)	(1,571,283)	(1,585,556)	(1,599,828)	(1,614,101)	(1,628,374)	(1,642,647)	(1,656,920)	(1,671,192)	(1,685,465)	(1,699,738)	(1,714,011)	(1,728,284)	
4 CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2+3+4) (A)	4,522,381	4,508,108	4,493,835	4,479,562	4,465,290	4,451,017	4,436,744	4,422,471	4,408,198	4,393,926	4,379,653	4,365,380	4,351,107	
6 Average Net Investment		4,515,244	4,500,972	4,486,699	4,472,426	4,458,153	4,443,880	4,429,608	4,415,335	4,401,062	4,386,789	4,372,516	4,358,244	
7 Return on Average Net Investment														
a Equity Component (D)		20,788	20,722	20,657	20,591	20,525	20,460	21,213	21,145	21,077	21,008	20,940	20,872	249,998
b Debt Component		5,247	5,230	5,214	5,197	5,180	5,164	4,647	4,632	4,617	4,602	4,587	4,572	58,887
8 Investment Expenses														
a Depreciation (E)		14,273	14,273	14,273	14,273	14,273	14,273	14,273	14,273	14,273	14,273	14,273	14,273	171,274
b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (H)		40,308	40,225	40,143	40,061	39,979	39,896	40,133	40,050	39,966	39,883	39,800	39,716	480,159

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2020 THROUGH DECEMBER 2020
427-General Water Quality - Base

Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1 Investments														
a Expenditures/Additions		144,305	0	0	0	0	0	0	0	0	0	0	0	144,305
b Clearings to Plant		144,305	0	0	0	0	0	0	0	0	0	0	0	144,305
c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2 Plant-in-Service/Depreciation Base (B)	852,461	996,766	996,766	996,766	996,766	996,766	996,766	996,766	996,766	996,766	996,766	996,766	996,766	
3 Less: Accumulated Depreciation (C)	(50,034)	(53,116)	(56,439)	(59,761)	(63,084)	(66,406)	(69,729)	(73,051)	(76,374)	(79,696)	(83,019)	(86,341)	(89,664)	
4 CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Crist Closed Ash Landfill Reg Asset	0	2,401,279	2,451,043	2,474,765	2,459,149	2,498,268	2,591,425	2,705,599	2,625,258	2,641,656	2,636,647	2,717,781	4,049,961	
6 Net Investment (Lines 2 + 3 + 4) (A)	802,427	3,344,929	3,391,370	3,411,770	3,392,832	3,428,628	3,518,462	3,629,313	3,545,650	3,558,725	3,550,394	3,628,205	4,957,063	
6 Average Net Investment		2,073,678	3,368,150	3,401,570	3,402,301	3,410,730	3,473,545	3,573,888	3,587,482	3,552,188	3,554,560	3,589,300	4,292,634	
7 Return on Average Net Investment														
a Equity Component (D)		9,547	15,507	15,661	15,664	15,703	15,992	17,115	17,180	17,011	17,023	17,189	20,557	194,151
b Debt Component		2,410	3,914	3,953	3,953	3,963	4,036	3,749	3,763	3,726	3,729	3,765	4,503	45,464
8 Investment Expenses														
a Depreciation (E)		3,082	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	39,630
b Amortization (F)		4,009	8,114	8,264	8,305	8,372	8,621	8,996	9,082	9,006	9,055	9,212	11,602	102,637
c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e Other (G)		0	57,878	31,986	(7,310)	47,490	101,778	123,170	(71,259)	25,404	4,046	90,346	1,343,783	1,747,311
9 Total System Recoverable Expenses (H)		19,048	30,857	31,200	31,245	31,361	31,972	33,183	33,348	33,066	33,129	33,489	39,985	381,883

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Associated to Regulatory Asset
(H) Line 7 + 8 (a through d)

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8A

JANUARY 2020 THROUGH DECEMBER 2020

428-Coal Combustion Residuals - Base

Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1 Investments				0	0	0	0							
a Expenditures/Additions		2,873,597	(9,615)	(36,164)	1,593,518	(11,956,638)	2,924,539	1,475,171	1,285,380	2,191,931	1,152,995	815,431	3,841,530	6,151,674
b Clearings to Plant		(658,051)	(231,446)	(640,898)	(57,163)	2,477,980	15,011,830	270,252	217,937	182,074	358,709	109,515	406,827	17,447,566
c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d Other		0	118,910	80,798	60,495	207,269	100,903	206,807	87,304	286,467	994,153	152,634	1,834,416	4,130,157
e PIS Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
f Accumulated Depreciation Adjustments		(76,099)	0	0	0	(183,226)	2,545,219	0	0	0	0	0	(577)	2,285,317
2 Plant-in-Service/Depreciation Base (B)	16,983,709	16,325,658	16,094,212	15,453,314	15,396,150	17,874,131	32,885,961	33,156,213	33,374,150	33,556,224	33,914,933	34,024,447	34,431,275	
3 Less: Accumulated Depreciation (C)	(34,617,746)	(34,778,987)	(34,744,317)	(34,746,964)	(34,769,274)	(34,830,255)	(37,389,070)	(37,297,328)	(37,325,537)	(37,154,950)	(36,277,173)	(36,241,342)	(34,523,627)	
4 CWIP - Non Interest Bearing	19,242,153	22,115,749	22,106,134	22,069,971	23,663,488	11,706,850	14,631,389	16,106,560	17,391,939	19,583,871	20,736,866	21,552,296	25,393,827	
Ash Pond Closure Regulatory Asset	9,679,682	9,910,399	10,232,635	10,700,657	10,793,921	11,866,281	14,608,975	15,229,321	15,728,087	17,738,127	20,763,819	22,592,885	25,593,314	
5 Net Investment (Lines 2 + 3 + 4) (A)	11,287,797	13,572,820	13,688,665	13,476,978	15,084,287	6,617,007	24,737,255	27,194,765	29,168,639	33,723,271	39,138,445	41,928,287	50,894,789	
6 Average Net Investment		12,430,309	13,630,742	13,582,821	14,280,632	10,850,647	15,677,131	25,966,010	28,181,702	31,445,955	36,430,858	40,533,366	46,411,538	
7 Return on Average Net Investment														
a Equity Component (D)		57,229	62,756	62,535	65,748	49,956	72,178	124,351	134,962	150,595	174,467	194,114	222,265	1,371,157
b Debt Component		14,444	15,839	15,783	16,594	12,608	18,217	27,238	29,563	32,987	38,216	42,520	48,686	312,694
8 Investment Expenses														
a Depreciation (E)		30,282	29,380	28,584	27,945	30,164	59,639	60,205	60,652	61,019	61,514	61,944	62,417	573,743
b Amortization (F)		16,425	16,914	17,601	18,099	19,101	22,315	25,157	26,132	28,268	32,515	36,618	40,707	299,852
c Dismantlement		54,861	54,861	54,861	54,861	54,861	54,861	54,861	54,861	54,861	54,861	54,861	54,861	658,328
d Property Taxes		7,248	6,073	6,073	6,073	6,073	6,073	6,073	6,073	6,073	6,073	6,073	6,073	74,053
e Other (G)		247,143	339,150	485,623	111,363	1,091,460	2,765,009	645,502	524,899	2,038,308	3,058,207	1,865,685	3,041,136	16,213,484
9 Total System Recoverable Expenses (H)		180,489	185,822	185,438	189,319	172,763	233,281	297,885	312,243	333,802	367,647	396,130	435,009	3,289,828

Notes:

(A) "Other" Includes Cost of Removal for Daniel 1&2 and Scherer Ash Ponds
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Associated to Regulatory Asset
(H) Line 7 + 8 (a through d)

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2020 THROUGH DECEMBER 2020
428-Coal Combustion Residuals - Intermediate

	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1	Investments														
	a Expenditures/Additions		800,546	1,373,066	2,144,358	1,947,211	2,297,399	1,524,535	2,076,184	2,704,312	1,841,700	624,078	2,147,567	2,968,497	22,449,451
	b Clearings to Plant		0	0	0	0	(24,544)	0	0	0	57,083	0	0	0	32,539
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	24,544	0	0	0	(28,279)	0	0	0	(3,735)
	e PIS Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	2,601,638	2,601,638	2,601,638	2,601,638	2,601,638	2,577,093	2,577,093	2,577,093	2,577,093	2,634,177	2,634,177	2,634,177	2,634,177	
3	Less: Accumulated Depreciation (C)	(20,842)	(31,032)	(41,222)	(51,412)	(61,601)	(47,199)	(57,292)	(67,386)	(77,479)	(115,964)	(126,281)	(136,599)	(146,916)	
4	CWIP - Non Interest Bearing	53,723,548	54,524,094	55,897,160	58,041,517	59,988,728	62,286,127	63,810,662	65,886,846	68,591,158	70,432,858	71,056,936	73,204,503	76,172,999	
5	Ash Pond Closure Regulatory Asset	1,428,635	1,546,086	1,595,490	1,645,894	1,857,849	1,806,884	3,422,181	3,556,056	4,861,223	4,683,410	5,972,537	7,222,686	8,335,180	
6	Net Investment (Lines 2 + 3 + 4) (A)	57,732,978	58,640,786	60,053,066	62,237,638	64,386,614	66,622,906	69,752,644	71,952,610	75,951,996	77,634,481	79,537,368	82,924,767	86,995,440	
7	Average Net Investment		58,186,882	59,346,926	61,145,352	63,312,126	65,504,760	68,187,775	70,852,627	73,952,303	76,793,238	78,585,925	81,231,067	84,960,103	
8	Return on Average Net Investment														
	a Equity Component (D)		267,892	273,233	281,513	291,489	301,584	313,937	339,313	354,158	367,763	376,348	389,016	406,874	3,963,119
	b Debt Component		67,613	68,961	71,051	73,569	76,117	79,234	74,324	77,576	80,556	82,437	85,211	89,123	925,772
9	Investment Expenses														
	a Depreciation (E)		10,190	10,190	10,190	10,190	10,142	10,094	10,094	10,094	10,205	10,317	10,317	10,317	122,339
	b Amortization (F)		2,494	2,637	2,724	2,948	3,087	4,397	5,863	7,073	8,025	8,965	11,098	13,087	72,399
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		119,945	52,041	53,129	214,903	(47,877)	1,619,693	139,738	1,312,240	(169,788)	1,298,092	1,261,247	1,125,581	6,978,944
10	Total System Recoverable Expenses (H)		348,189	355,021	365,478	378,195	390,929	407,661	429,594	448,900	466,549	478,067	495,642	519,401	5,083,629

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8A

JANUARY 2020 THROUGH DECEMBER 2020

429-Steam Electric Effluent Limitations Guidelines - Base

Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1 Investments														
a Expenditures/Additions		75,272	9,951	10,627	26,521	21,637	24,432	9,011	12,407	40,633	(412,691)	428,395	14,768	260,962
b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
e PIS Adjustments		(384,575)	0	0	0	384,705	0	0	0	0	0	0	0	131
f Accumulated Depreciation Adjustments		(1,534)	0	0	0	(5,972)	0	0	0	0	0	0	0	(7,506)
2 Plant-in-Service/Depreciation Base (B)	6,042,460	5,657,885	5,657,885	5,657,885	5,657,885	6,042,591	6,042,591	6,042,591	6,042,591	6,042,591	6,042,591	6,042,591	6,042,591	
3 Less: Accumulated Depreciation (C)	(410,569)	(430,962)	(449,821)	(468,681)	(487,541)	(513,078)	(532,643)	(552,208)	(571,772)	(591,337)	(610,902)	(630,467)	(650,032)	
4 CWIP - Non Interest Bearing	653,027	728,298	738,250	748,876	775,397	797,034	821,466	830,477	842,884	883,517	470,826	899,221	913,989	
5 Net Investment (Lines 2 + 3 + 4) (A)	6,284,918	5,955,222	5,946,313	5,938,081	5,945,742	6,326,547	6,331,414	6,320,860	6,313,702	6,334,771	5,902,515	6,311,345	6,306,548	
6 Average Net Investment		6,120,070	5,950,768	5,942,197	5,941,911	6,136,144	6,328,981	6,326,137	6,317,281	6,324,236	6,118,643	6,106,930	6,308,946	
7 Return on Average Net Investment														
a Equity Component (D)		28,177	27,397	27,358	27,357	28,251	29,139	30,296	30,253	30,287	29,302	29,246	30,214	347,276
b Debt Component		7,112	6,915	6,905	6,905	7,130	7,354	6,636	6,627	6,634	6,418	6,406	6,618	81,660
8 Investment Expenses														
a Depreciation (E)		18,860	18,860	18,860	18,860	19,565	19,565	19,565	19,565	19,565	19,565	19,565	19,565	231,958
b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d Property Taxes		237	197	197	197	197	197	197	197	197	197	197	197	2,407
e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (H)		54,385	53,369	53,320	53,318	55,143	56,255	56,694	56,642	56,683	55,483	55,414	56,594	663,301

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8A

JANUARY 2020 THROUGH DECEMBER 2020

430-316b Cooling Water Intake Structure Regulation - Intermediate

Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12 Month Total
1 Investments														
a Expenditures/Additions		31,976	336,336	188,149	184,306	12,795	8,554	8,749	557,790	17,982	21,860	33,967	2,397,679	3,800,143
b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d Other		3,198	36,146	18,815	0	0	0	0	0	0	0	0	0	58,158
e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2 Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3 Less: Accumulated Depreciation (C)	29,428	32,625	68,771	87,586	87,586	87,586	87,586	87,586	87,586	87,586	87,586	87,586	87,586	
4 CWIP - Non Interest Bearing	318,704	350,680	687,016	875,165	1,059,471	1,072,266	1,080,821	1,089,569	1,647,360	1,665,341	1,687,201	1,721,167	4,118,847	
5 Net Investment (Lines 2 + 3 + 4) (A)	348,132	383,305	755,786	962,751	1,147,057	1,159,852	1,168,406	1,177,155	1,734,945	1,752,927	1,774,787	1,808,753	4,206,432	
6 Average Net Investment		365,718	569,546	859,269	1,054,904	1,153,455	1,164,129	1,172,781	1,456,050	1,743,936	1,763,857	1,791,770	3,007,593	
7 Return on Average Net Investment														
a Equity Component (D)		1,684	2,622	3,956	4,857	5,311	5,360	5,616	6,973	8,352	8,447	8,581	14,403	76,161
b Debt Component		425	662	998	1,226	1,340	1,353	1,230	1,527	1,829	1,850	1,880	3,155	17,476
8 Investment Expenses														
a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (H)		2,109	3,284	4,955	6,083	6,651	6,712	6,847	8,500	10,181	10,297	10,460	17,558	93,637

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

FORM 42-8A

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2020 THROUGH DECEMBER 2020
For Program: Regulatory Asset Smith Units 1 & 2

		Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	Twelve Month Total
1	Regulatory Asset Balance [B]	18,498,355	18,498,355	18,379,776	18,261,197	18,142,617	18,024,038	17,905,459	17,786,880	17,668,301	17,549,721	17,431,142	17,312,563	17,193,984	
2	Less Amortization [C]	0	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	
3	Net Regulatory Asset Balance (Lines 1 + 2) [A]	18,498,355	18,379,776	18,261,197	18,142,617	18,024,038	17,905,459	17,786,880	17,668,301	17,549,721	17,431,142	17,312,563	17,193,984	17,075,405	
4	Average Regulatory Asset Balance		18,439,065	18,320,486	18,201,907	18,083,328	17,964,749	17,846,169	17,727,590	17,609,011	17,490,432	17,371,853	17,253,273	17,134,694	
5	Return on Average Regulatory Asset Balance														
a	Equity Component (Line 6 x Equity Component x 1/12) [D]		84,893	84,348	83,802	83,256	82,710	82,164	84,897	84,330	83,762	83,194	82,626	82,058	1,002,038
b	Debt Component (Line 6 x Debt Component x 1/12)		21,426	21,288	21,151	21,013	20,875	20,737	18,596	18,472	18,347	18,223	18,099	17,974	236,202
6	Amortization Expense														
a	Recoverable Costs Allocated to Energy		118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	1,422,950
b	Other [E]		0	0	0	0	0	0	0	0	0	0	0	0	0
7	Total System Recoverable Expenses (Lines 5 + 6)		224,899	224,215	223,531	222,848	222,164	221,480	222,073	221,381	220,688	219,996	219,304	218,612	2,661,190

Notes:
(A) End of period Regulatory Asset Balance.
(B) Beginning of period Regulatory Asset Balance.
(C) Regulatory Asset has a 15 year amortization period.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Description and reason for "Other" adjustments to regulatory asset.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2020 THROUGH DECEMBER 2020
For Project: Annual NOx Allowances

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	Twelve Month Total
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Working Capital														
	a FERC 158.1 Allowance Inventory	8,684	7,780	8,066	8,066	7,923	7,923	7,923	7,367	7,367	7,367	6,293	6,293	6,469	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Reg. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Total Working Capital Balance	8,684	7,780	8,066	8,066	7,923	7,923	7,923	7,367	7,367	7,367	6,293	6,293	6,469	
4	Average Net Working Capital Balance		8,232	7,923	8,066	7,994	7,923	7,923	7,645	7,367	7,367	6,830	6,293	6,381	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		38	36	37	37	36	36	37	35	35	33	30	31	422
	b Debt Component (Line 4 x Debt Component x 1/12)		10	9	9	9	9	9	8	8	8	7	7	7	100
6	Total Return Component (B)		47	46	47	46	46	46	45	43	43	40	37	37	522

Notes:
(A) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(B) Line 6 is reported on Schedule 7A.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8A

JANUARY 2020 THROUGH DECEMBER 2020
For Program: SO2 Allowances

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	Twelve Month Total
1	Investments														
a	Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
b	Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
c	Auction Proceeds/Other		0	0	0	24	0	0	0	0	0	0	0	0	
2	Working Capital														
a	FERC 158.1 Allowance Inventory	6,302,727	6,298,434	6,297,039	6,297,039	6,278,193	6,278,178	6,278,183	6,292,451	6,292,456	6,292,460	6,289,576	6,289,580	6,285,159	
b	FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
c	FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
d	FERC 254 Regulatory Liabilities - Gains	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Total Working Capital Balance	6,302,727	6,298,434	6,297,039	6,297,039	6,278,193	6,278,178	6,278,183	6,292,451	6,292,456	6,292,460	6,289,576	6,289,580	6,285,159	
4	Average Net Working Capital Balance		6,300,581	6,297,737	6,297,039	6,287,616	6,278,186	6,278,181	6,285,317	6,292,453	6,292,458	6,291,018	6,289,578	6,287,370	
5	Return on Average Net Working Capital Balance														
a	Equity Component (Line 4 x Equity Component x 1/12) [(A)]		29,008	28,995	28,992	28,948	28,905	28,905	30,100	30,135	30,135	30,128	30,121	30,110	354,480
b	Debt Component (Line 4 x Debt Component x 1/12)		7,321	7,318	7,317	7,306	7,295	7,295	6,593	6,601	6,601	6,599	6,598	6,595	83,440
6	Total Return Component [(B)]		36,329	36,313	36,309	36,254	36,200	36,200	36,694	36,735	36,735	36,727	36,719	36,706	437,921

Notes:
(A) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(B) Line 6 is reported on Schedule 7A.

Gulf Power Company
Environmental Cost Recovery Clause
2020 Annual Capital Depreciation Schedule

Project	Function	Major Location	Plant	Depreciation Rate	Type	12/1/2020
401-Air Quality Assurance Testing	01 - Intangible Plant	G:Intangible Plant	31670	14.286%	Amortization	-
	02 - Steam Generation Plant	G:Crist Plant	31670	14.286%	Amortization	83,954
401-Air Quality Assurance Testing Total						83,954
402-Crist 5, 6 & 7 Precipitator Projects	02 - Steam Generation Plant	CRIST PLANT - Common A	31400	4.000%	Depreciation	291,139
		CRIST PLANT - Unit 5	31200	4.000%	Depreciation	453,061
		CRIST PLANT - Unit 6	31200	4.000%	Depreciation	7,646,441
		CRIST PLANT - Unit 7	31200	4.000%	Depreciation	147,682
402-Crist 5, 6 & 7 Precipitator Projects Total						8,538,323
403-Crist 7 Flue Gas Conditioning	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31200	4.000%	Depreciation	-
403-Crist 7 Flue Gas Conditioning Total						-
404-Low NOx Burners, Crist 6 & 7	02 - Steam Generation Plant	CRIST PLANT - Common A	31200	4.000%	Depreciation	131,183
		CRIST PLANT - Unit 6	31200	4.000%	Depreciation	3,912,618
			31400	4.000%	Depreciation	11,338
		CRIST PLANT - Unit 7	31200	4.000%	Depreciation	9,284,648
			31500	4.000%	Depreciation	44,385
		G:Crist Plant	31670	14.286%	Amortization	143,759
404-Low NOx Burners, Crist 6 & 7 Total						13,527,932
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.000%	Depreciation	350,454
			31200	4.000%	Depreciation	3,132,384
		CRIST PLANT - Unit 4	31200	4.000%	Depreciation	24,046
		CRIST PLANT - Unit 5	31200	4.000%	Depreciation	20,502
		CRIST PLANT - Unit 6	31200	4.000%	Depreciation	217,721
		CRIST PLANT - Unit 7	31200	4.000%	Depreciation	341,530
		DANIEL P-Com 1-2	31200	3.000%	Depreciation	356,393
			31500	3.000%	Depreciation	196,553
			31670	14.286%	Amortization	3,097
		DANIEL PLANT - Unit 1	31200	3.000%	Depreciation	32,584
		DANIEL PLANT - Unit 2	31200	3.000%	Depreciation	37,519
405-CEMS - Plants Crist & Daniel Total						4,712,783
406-Substation Contamination Remediation	06 - Transmission Plant - Electric	G:Transmission Substations	35200	1.700%	Depreciation	339,156
	07 - Distribution Plant - Electric	G:Distribution	36100	1.900%	Depreciation	587,654
			36200	3.100%	Depreciation	2,959,695
406-Substation Contamination Remediation Total						3,886,505
407-Raw Water Well Flowmeters Plants Crist & Smith	02 - Steam Generation Plant	CRIST PLANT - Common A	31200	4.000%	Depreciation	149,950
	05 - Other Generation Plant	G:Smith Common - CT and C(	34300	4.700%	Depreciation	-
407-Raw Water Well Flowmeters Plants Crist & Smith Total						149,950
408-Crist Cooling Tower Cell	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31200	4.000%	Depreciation	-
408-Crist Cooling Tower Cell Total						-
409-Crist Dechlorination System	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.000%	Depreciation	76,079
			31400	4.000%	Depreciation	304,619
409-Crist Dechlorination System Total						380,697
410-Crist Diesel Fuel Oil Remediation	02 - Steam Generation Plant	CRIST PLANT - Common A	31200	4.000%	Depreciation	20,968
410-Crist Diesel Fuel Oil Remediation Total						20,968
411-Crist Bulk Tanker Unloading Second Containment	02 - Steam Generation Plant	CRIST PLANT - Common A	31200	4.000%	Depreciation	50,748
411-Crist Bulk Tanker Unloading Second Containment Total						50,748
412-Crist IWW Sampling System	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.000%	Depreciation	59,543
412-Crist IWW Sampling System Total						59,543
413-Sodium Injection System	02 - Steam Generation Plant	CRIST PLANT - Common A	31200	4.000%	Depreciation	-
413-Sodium Injection System Total						-
414-Smith Stormwater Collection System	05 - Other Generation Plant	G:Smith Common - CT and C(	34100	4.700%	Depreciation	2,601,079
			34500	4.700%	Depreciation	163,300
414-Smith Stormwater Collection System Total						2,764,379
415-Smith Waste Water Treatment Facility	05 - Other Generation Plant	G:Smith Common - CT and C(	34100	4.700%	Depreciation	643,620
415-Smith Waste Water Treatment Facility Total						643,620
416-Daniel Ash Management Project	02 - Steam Generation Plant	DANIEL P-Com 1-2	31100	3.000%	Depreciation	7,157,673
			31200	3.000%	Depreciation	5,258,246
		DANIEL P-Com 1-4	31200	3.000%	Depreciation	1,633
			31670	14.286%	Amortization	639
		DANIEL PLANT - Unit 1	31500	3.000%	Depreciation	2,521,370
416-Daniel Ash Management Project Total						14,939,561
417-Smith Water Conservation	05 - Other Generation Plant	G:Smith Common - CT and C(	34100	4.700%	Depreciation	669,502
			34500	4.700%	Depreciation	2,059,084
		G:Smith Unit 3 - Combined Cy	34100	4.700%	Depreciation	18,853,016
			34500	4.700%	Depreciation	9,159
417-Smith Water Conservation Total						21,590,761
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.000%	Depreciation	1,279,759
			31200	4.000%	Depreciation	804,175
			31600	4.000%	Depreciation	149,244
		CRIST PLANT - Unit 4	31200	4.000%	Depreciation	1,315,960

Project	Function	Major Location	Plant	Depreciation Rate	Type	12/1/2020
		CRIST PLANT - Unit 5	31200	4.000%	Depreciation	1,314,974
		CRIST PLANT - Unit 6	31100	4.000%	Depreciation	2
			31200	4.000%	Depreciation	7,583,044
			31500	4.000%	Depreciation	263,775
		CRIST PLANT - Unit 7	31200	4.000%	Depreciation	17,412,701
			31500	4.000%	Depreciation	8,173,896
		G:Crist Plant	31670	14.286%	Amortization	790,482
419-Crist FDEP Agreement for Ozone Attainment Total						39,088,012
420-SPCC Compliance	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.000%	Depreciation	919,836
	05 - Other Generation Plant	G:Smith Common - CT and C(	34100	4.700%	Depreciation	14,895
	08 - General Plant	G:General Plant	39400	14.286%	Depreciation	13,195
420-SPCC Compliance Total						947,925
421-Crist Common FTIR Monitor	02 - Steam Generation Plant	CRIST PLANT - Common A	31600	4.000%	Depreciation	-
421-Crist Common FTIR Monitor Total						-
422-Precipitator Upgrades for CAM Compliance	02 - Steam Generation Plant	CRIST PLANT - Unit 4	31200	4.000%	Depreciation	-
		CRIST PLANT - Unit 5	31200	4.000%	Depreciation	-
422-Precipitator Upgrades for CAM Compliance Total						-
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.000%	Depreciation	127,481
			31200	4.000%	Depreciation	1,861,971
			31400	4.000%	Depreciation	8,510,363
			31500	4.000%	Depreciation	2,544,385
			31600	4.000%	Depreciation	353,327
		CRIST PLANT - Unit 4	31200	4.000%	Depreciation	190,220
		CRIST PLANT - Unit 5	31200	4.000%	Depreciation	137,801
		CRIST PLANT - Unit 6	31200	4.000%	Depreciation	207,297
			31400	4.000%	Depreciation	857,763
			31500	4.000%	Depreciation	39,519
		CRIST PLANT - Unit 7	31200	4.000%	Depreciation	195,157
			31400	4.000%	Depreciation	131,244
424-Crist Water Conservation Total						15,156,528
425-Plant NPDES Permit Compliance Projects	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.000%	Depreciation	325,432
		CRIST PLANT - Unit 4	31400	4.000%	Depreciation	1,579,996
		CRIST PLANT - Unit 5	31400	4.000%	Depreciation	1,773,231
		CRIST PLANT - Unit 6	31200	4.000%	Depreciation	440,705
			31400	4.000%	Depreciation	5,827,708
	05 - Other Generation Plant	G:Smith Common - CT and C(	34400	4.700%	Depreciation	3,798,266
425-Plant NPDES Permit Compliance Projects Total						13,745,338
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.000%	Depreciation	60,330,270
			31200	4.000%	Depreciation	29,641,207
			31400	4.000%	Depreciation	257,354
			31500	4.000%	Depreciation	79,936,850
			31600	4.000%	Depreciation	2,213,173
		CRIST PLANT - Unit 4	31200	4.000%	Depreciation	4,624,344
			31500	4.000%	Depreciation	2,015,231
		CRIST PLANT - Unit 5	31200	4.000%	Depreciation	5,644,235
			31500	4.000%	Depreciation	2,230,365
		CRIST PLANT - Unit 6	31200	4.000%	Depreciation	48,881,071
			31500	4.000%	Depreciation	25,120,806
		CRIST PLANT - Unit 7	31200	4.000%	Depreciation	16,727,944
			31400	4.000%	Depreciation	27,648,320
			31500	4.000%	Depreciation	2,126,229
		DANIEL P-Com 1-2	31100	3.000%	Depreciation	10,151,205
			31200	3.000%	Depreciation	210,352,874
			31500	3.000%	Depreciation	16,402,310
			31600	3.000%	Depreciation	334,923
			31650	20.000%	Amortization	226,142
			31670	14.286%	Amortization	377,947
		DANIEL PLANT - Unit 1	31100	3.000%	Depreciation	337,967
			31200	3.000%	Depreciation	94,573,715
			31500	3.000%	Depreciation	929,672
			31600	3.000%	Depreciation	151,046
		DANIEL PLANT - Unit 2	31100	3.000%	Depreciation	-
			31200	3.000%	Depreciation	40,287,908
			31600	3.000%	Depreciation	(22,658)
			31650	20.000%	Amortization	-
			31670	14.286%	Amortization	22,658
		G:Crist Plant	31670	14.286%	Amortization	965,729
		SCHERER PLANT-Common /	31100	2.200%	Depreciation	798,405
			31200	2.200%	Depreciation	8,873,354
			31500	2.200%	Depreciation	854,675
			31670	14.286%	Amortization	20,761
		SCHERER PLANT-Common E	31100	2.200%	Depreciation	960,382
			31200	2.200%	Depreciation	13,347,502
			31500	2.200%	Depreciation	126,817
			31600	2.200%	Depreciation	557

Project	Function	Major Location	Plant	Depreciation Rate	Type	12/1/2020
			31670	14.286%	Amortization	85,069
		SCHERER PLANT-UNIT #3	31100	2.200%	Depreciation	4,550,217
			31200	2.200%	Depreciation	145,853,249
			31500	2.200%	Depreciation	5,888,098
			31600	2.200%	Depreciation	612
			31670	14.286%	Amortization	19,404
	05 - Other Generation Plant	G:Smith Plant CT	34200	6.300%	Depreciation	229,742
	06 - Transmission Plant - Electric	G:Transmission 115-500KV Li	35400	2.000%	Depreciation	565,062
			35500	4.600%	Depreciation	502,662
			35600	2.600%	Depreciation	576,009
		G:Transmission Substations	35200	1.700%	Depreciation	211,336
			35300	2.800%	Depreciation	4,224,323
426-Air Quality Compliance Program Total						870,177,072
427-General Water Quality	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.000%	Depreciation	996,766
427-General Water Quality Total						996,766
428-Coal Combustion Residuals	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.000%	Depreciation	675,957
		DANIEL P-Com 1-2	31100	3.000%	Depreciation	104,724
		G:Crist Plant	31100	0.000%	Dismantlement	-
		G:Daniel Plant	31100	0.000%	Dismantlement	-
		G:Scherer Plant	31100	0.000%	Dismantlement	-
		SCHERER PLANT-Common E	31000	0.000%	Depreciation	773,371
			31100	2.200%	Depreciation	16,068,736
			31200	2.200%	Depreciation	9,745,780
		SCHERER PLANT-UNIT #3	31100	2.200%	Depreciation	535,136
			31200	2.200%	Depreciation	6,527,571
	05 - Other Generation Plant	G:Smith Common - CT and C(	34100	4.700%	Depreciation	1,451,586
			34500	4.700%	Depreciation	1,027,022
			34600	4.700%	Depreciation	155,569
	08 - General Plant	G:General Plant	39000	2.000%	Depreciation	-
428-Coal Combustion Residuals Total						37,065,451
429-Steam Electric Effluent Limitations Guidelines	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.000%	Depreciation	5,657,885
		SCHERER PLANT-UNIT #3	31200	2.200%	Depreciation	384,705
429-Steam Electric Effluent Limitations Guidelines Total						6,042,591
430-316b Cooling Water Intake Structure Regulation	05 - Other Generation Plant	G:Smith Common - CT and C(	34300	4.700%	Depreciation	-
430-316b Cooling Water Intake Structure Regulation Total						-
Grand Total						1,054,569,405

Form 42-9A

January 2020 - June 2020
FPSC Capital Structure and Cost Rates

Line	Capital Component	(1) Jurisdictional Rate Base Test Year ($000's)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %	(5) Revenue Requirement Rate %	(6) Monthly Revenue Requirement Rate %
1	Long-Term Debt	894,848	34.5416	3.91	1.3519	1.3519	
2	Short-Term Debt	20,976	0.8097	2.96	0.0240	0.0240	
3	Preferred Stock	0	0.0000	0.00	0.0000	0.0000	
4	Common Stock	1,053,681	40.6728	10.25	4.1690	5.5234	
5	Customer Deposits	22,119	0.8538	2.08	0.0178	0.0178	
6	Deferred Taxes	598,399	23.0986				
7	Investment Tax Credit	608	0.0235	7.34	0.0017	0.0021	
8	Total	2,590,631	100.0000		5.5644	6.9192	0.5766
	ITC Component:						
9	Debt	894,848	45.9243	3.91	1.7974	0.0004	
10	Equity-Preferred	0	0.0000	0.00	0.0000	0.0000	
11	-Common	1,053,681	54.0757	10.25	5.5428	0.0017	
12		1,948,530	100.0000		7.3402	0.0021	
	Breakdown of Revenue Requirement Rate of Return between Debt and Equity:						
13	Total Debt Component (Lines 1, 2, 5, and 9)					1.3941	0.1162
14	Total Equity Component (Lines 3, 4, 10, and 11)					5.5251	0.4604
15	Total Revenue Requirement Rate of Return					6.9192	0.5766

Column:
(1) Based on the May 2019 Surveillance Report, Schedule 4.
Adjusted to achieve the 53.5% equity ratio as prescribed in the 2018 Tax Reform Settlement Agreement in Docket No. 20180039-EI.
(2) Column (1) / Total Column (1)
(3) Based on the May 2019 Surveillance Report, Schedule 4.
(4) Column (2) x Column (3)
(5) For equity components: Column (4) / (1-.245218); 24.5218% = effective income tax rate
For debt components: Column (4)
(6) Column (5) /12

Form 42-9A

July 2020 - December 2020
FPSC Capital Structure and Cost Rates

Line	Capital Component	(1) Jurisdictional Rate Base Test Year ($000's)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %	(5) Revenue Requirement Rate %	(6) Monthly Revenue Requirement Rate %
1	Long-Term Debt	877,077	31.6409	3.76	1.1912	1.1912	
2	Short-Term Debt	141,485	5.1041	0.92	0.0470	0.0470	
3	Preferred Stock	0	0.0000	0.00	0.0000	0.0000	
4	Common Stock	1,171,867	42.2754	10.25	4.3332	5.7410	
5	Customer Deposits	20,015	0.7220	2.69	0.0194	0.0194	
6	Deferred Taxes	558,907	20.1627				
7	Investment Tax Credit	2,632	0.0949	7.47	0.0071	0.0071	
8	Total	2,771,983	100.0000		5.5979	7.0057	0.5838
	ITC Component:						
9	Debt	877,077	42.8063	3.76	1.6116	0.0015	
10	Equity-Preferred	0	0.0000	0.00	0.0000	0.0000	
11	-Common	1,171,867	57.1937	10.25	5.8624	0.0056	
12		2,048,944	100.0000		7.4740	0.0071	
	Breakdown of Revenue Requirement Rate of Return between Debt and Equity:						
13	Total Debt Component (Lines 1, 2, 5, and 9)					1.2591	0.1049
14	Total Equity Component (Lines 3, 4, 10, and 11)					5.7466	0.4789
15	Total Revenue Requirement Rate of Return					7.0057	0.5838

Column:
(1) Based on the May 2020 Surveillance Report, Schedule 4.
Adjusted to achieve the 53.5% equity ratio as prescribed in the 2018 Tax Reform Settlement Agreement in Docket No. 20180039-EI.
(2) Column (1) / Total Column (1)
(3) Based on the May 2020 Surveillance Report, Schedule 4.
(4) Column (2) x Column (3)
(5) For equity components: Column (4) / (1-.245218); 24.5218% = effective income tax rate
For debt components: Column (4)
(6) Column (5) /12

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE ACTUAL ESTIMATED TRUE-UP AMOUNT FOR THE PERIOD

JANUARY 2021 THROUGH DECEMBER 2021

	2021
1. Over/(Under) Recovery for the Current Period (Form 42-2E, Line 5)	$3,811,100
2. Interest Provision (Form 42-2E, Line 6)	$5,568
3. Prior Period Adjustment (Form 42-2E, Line 10)	-
4. Actual/Estimated True-up to be refunded/(recovered)	$3,816,668

Note: Totals may not add due to rounding

FORM: 42-2E

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE ACTUAL ESTIMATED TRUE-UP AMOUNT FOR THE PERIOD

JANUARY 2021 THROUGH DECEMBER 2021

	January Actual	February Actual	March Actual	April Actual	May Actual	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Total
1. ECRC Revenues (net of Revenue Taxes)	$15,420,422	$12,284,941	$10,041,467	$10,067,898	$13,020,426	$14,610,134	$16,388,061	$16,530,422	$15,472,834	$13,027,226	$10,965,878	$11,249,446	$159,079,155
2. True-up Provision [(a)]	$1,129,466	$1,129,466	$1,129,466	$1,129,466	$1,129,466	$1,129,466	$1,129,466	$1,129,466	$1,129,466	$1,129,466	$1,129,466	$1,129,466	$13,553,587
3. ECRC Revenues Applicable to Period (Lines 1 + 2)	$16,549,887	$13,414,407	$11,170,932	$11,197,364	$14,149,892	$15,739,599	$17,517,526	$17,659,888	$16,602,299	$14,156,692	$12,095,343	$12,378,912	$172,632,740
4. Jurisdictional ECRC Costs													
a. O&M Activities (Form 42-5E-2, Line 6)	$1,174,261	$1,241,218	$1,423,560	$1,357,578	$1,418,724	$1,739,109	$1,553,984	$14,032,029	$1,313,784	$1,439,550	$1,240,207	$1,743,327	$29,677,333
b. Capital Investment Projects (Form 42-7E-2, Line 6)	$11,332,293	$11,591,362	$11,458,582	$11,522,829	$11,560,509	$11,566,372	$11,588,800	$11,615,290	$11,646,552	$11,697,355	$11,736,396	$11,827,966	$139,144,307
c. Total Jurisdictional ECRC Costs	$12,506,554	$12,832,579	$12,882,142	$12,880,408	$12,979,233	$13,305,481	$13,142,785	$25,647,320	$12,960,337	$13,136,905	$12,976,603	$13,571,293	$168,821,640
5. Over/(Under) Recovery (Line 3 - Line 4c)	$4,043,333	$581,828	($1,711,210)	($1,683,044)	$1,170,659	$2,434,119	$4,374,742	($7,987,432)	$3,641,963	$1,019,787	($881,259)	($1,192,381)	$3,811,100
6. Interest Provision (Form 42-3E, Line 10)	$913	$997	$1,025	$714	$374	$291	$366	$269	$160	$200	$165	$93	$5,568
7. Prior Periods True-Up to be (Collected)/Refunded	$13,553,587	$16,468,368	$15,921,728	$13,082,078	$10,270,283	$10,311,852	$11,616,795	$14,862,437	$5,745,808	$8,258,466	$8,148,988	$6,138,428	$13,553,587
a. Deferred True-Up [(b)]	($2,150,848)	($2,150,848)	($2,150,848)	($2,150,848)	($2,150,848)	($2,150,848)	($2,150,848)	($2,150,848)	($2,150,848)	($2,150,848)	($2,150,848)	($2,150,848)	
8. True-Up Collected /(Refunded) (See Line 2)	($1,129,466)	($1,129,466)	($1,129,466)	($1,129,466)	($1,129,466)	($1,129,466)	($1,129,466)	($1,129,466)	($1,129,466)	($1,129,466)	($1,129,466)	($1,129,466)	($13,553,587)
9. End of Period True-Up (Lines 5+6+7+7a+8)	$14,317,520	$13,770,880	$10,931,230	$8,119,435	$8,161,003	$9,465,947	$12,711,589	$3,594,960	$6,107,618	$5,998,140	$3,987,580	$1,665,826	$3,816,668
10. Adjustments to Period Total True-Up Including Interest	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11. End of Period Total Net True-Up (Lines 9+10)	$14,317,520	$13,770,880	$10,931,230	$8,119,435	$8,161,003	$9,465,947	$12,711,589	$3,594,960	$6,107,618	$5,998,140	$3,987,580	$1,665,826	$3,816,668

[(a)] As approved in Order No. PSC-2021-0115-PAA-EI issued March 22, 2021 and Order No. PSC-2020-0433-FOF-EI issued November 13, 2020.
[(b)] From FPL's 2020 Final True-up filed on April 1,2021.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
INTEREST CALCULATION

FORM: 42-3E

JANUARY 2021 THROUGH DECEMBER 2021

	January Actual	February Actual	March Actual	April Actual	May Actual	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Total
1. Beginning True-Up Amount (Form 42-2E, Lines 7 + 7a + 10)	$11,402,739	$14,317,520	$13,770,880	$10,931,230	$8,119,435	$8,161,003	$9,465,947	$12,711,589	$3,594,960	$6,107,618	$5,998,140	$3,987,580	N/A
2. Ending True-Up Amount before Interest (Line 1 + Form 42-2E Lines 5 + 8)	$14,316,607	$13,769,882	$10,930,204	$8,118,720	$8,160,628	$9,465,656	$12,711,223	$3,594,692	$6,107,457	$5,997,939	$3,987,415	$1,665,733	N/A
3. Total of Beginning & Ending True-Up (Lines 1 + 2)	$25,719,347	$28,087,402	$24,701,084	$19,049,950	$16,280,063	$17,626,660	$22,177,171	$16,306,281	$9,702,416	$12,105,557	$9,985,554	$5,653,312	N/A
4. Average True-Up Amount (Line 3 x 1/2)	$12,859,673	$14,043,701	$12,350,542	$9,524,975	$8,140,031	$8,813,330	$11,088,585	$8,153,140	$4,851,208	$6,052,779	$4,992,777	$2,826,656	N/A
5. Interest Rate (First Day of Reporting Month)	0.09000%	0.08000%	0.09000%	0.11000%	0.07000%	0.04000%	0.04000%	0.04000%	0.04000%	0.04000%	0.04000%	0.04000%	N/A
6. Interest Rate (First Day of Subsequent Month)	0.08000%	0.09000%	0.11000%	0.07000%	0.04000%	0.04000%	0.04000%	0.04000%	0.04000%	0.04000%	0.04000%	0.04000%	N/A
7. Total of Beginning & Ending Interest Rates (Lines 5 + 6)	0.17000%	0.17000%	0.20000%	0.18000%	0.11000%	0.08000%	0.08000%	0.08000%	0.08000%	0.08000%	0.08000%	0.08000%	N/A
8. Average Interest Rate (Line 7 x 1/2)	0.08500%	0.08500%	0.10000%	0.09000%	0.05500%	0.04000%	0.04000%	0.04000%	0.04000%	0.04000%	0.04000%	0.04000%	N/A
9. Monthly Average Interest Rate (Line 8 x 1/12)	0.00710%	0.00710%	0.00830%	0.00750%	0.00460%	0.00330%	0.00330%	0.00330%	0.00330%	0.00330%	0.00330%	0.00330%	N/A
10. Interest Provision for the Month (Line 4 x Line 9)	$913	$997	$1,025	$714	$374	$291	$366	$269	$160	$200	$165	$93	$5,568

FORM 42-4E

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE ACTUAL ESTIMATED TRUE-UP AMOUNT FOR THE PERIOD

JANUARY 2021 THROUGH DECEMBER 2021
VARIANCE REPORT OF O&M ACTIVITIES

O&M PROJECT	ECRC - 2021 Actual Estimated True Up [(a)]	ECRC - 2021 Projections [(b)]	$ Dif ECRC 2020 Projections (c)	% Dif ECRC Projections (d)
2 - Air Emission Fees	$230,206	$279,230	($49,024)	(17.6%)
3 - Title V	$195,252	$195,866	($615)	(0.3%)
4 - Asbestos Fees	$1,500	$1,500	$0	
5 - Emission Monitoring	$478,937	$636,994	($158,057)	(24.8%)
6 - General Water Quality	$1,298,696	$1,632,757	($334,061)	(20.5%)
7 - Groundwater Contamination Investigation	$2,182,778	$2,182,923	($146)	(0.0%)
8 - State NPDES Administration	$41,150	$35,000	$6,150	17.6%
10 - Env Auditing/Assessment	$38,030	$32,930	$5,100	15.5%
11 - General Solid & Hazardous Waste	$815,298	$822,664	($7,365)	(0.9%)
12 - Above Ground Storage Tanks	$264,476	$243,131	$21,345	8.8%
19 - FDEP NOx Reduction Agreement	($16,223)	$97,678	($113,901)	(116.6%)
20 - Air Quality Compliance Program	$22,428,670	$23,673,016	($1,244,346)	(5.3%)
22 - Crist Water Conservation	$239,450	$258,703	($19,253)	(7.4%)
23 - Coal Combustion Residuals	$1,398,716	$1,745,127	($346,411)	(19.9%)
24 - Smith Water Conservation	$99,765	$122,500	($22,735)	(18.6%)
27 - Emission Allowances	$152,622	$3,888	$148,734	3,825.8%
Total	$29,849,324	$31,963,907	($2,114,583)	(6.6%)

[(a)] The 12-Month Totals on Form 42-5E
[(b)] Approved in Order No. PSC-2020-0433-FOF-EI issued November 13, 2020.
[(c)] Column (2) - Column (3)
[(d)] Column (4) / Column (3)

ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE ACTUAL ESTIMATED
TRUE-UP AMOUNT FOR THE PERIOD

JANUARY 2021 THROUGH DECEMBER 2021
O&M ACTIVITIES

Project #	O&M Project/Strata	January Actual	February Actual	March Actual	April Actual	May Actual	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	12-Month Total
2	Air Emission Fees - Intermediate	$0	$0	$16,454	$0	$0	$0	$0	$0	$0	$0	$0	$0	$16,454
2	Air Emission Fees - Base	$4,390	$2,919	$62,992	$2,988	$2,827	$2,971	$2,971	$2,971	$115,471	$2,971	$2,971	$2,971	$209,409
2	Air Emission Fees - Peaking	$0	$0	$4,343	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,343
3	Title V - Base	$6,170	$5,979	$6,798	$7,493	$6,308	$7,797	$11,175	$7,817	$7,812	$11,045	$6,395	$11,090	$95,879
3	Title V - Peaking	$3,148	$3,051	$3,469	$3,823	$3,218	$3,978	$5,701	$3,988	$3,986	$5,635	$3,263	$5,658	$48,919
3	Title V - Intermediate	$2,768	$7,042	$4,511	$3,122	$11,444	$2,664	$3,818	$2,670	$2,669	$3,773	$2,185	$3,789	$50,454
4	Asbestos Fees - Base	$0	$0	$0	$0	$0	$0	$500	$0	$0	$0	$0	$0	$500
4	Asbestos Fees - Intermediate	$0	$0	$1,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,000
5	Emission Monitoring - Base	($1,451)	$42,682	$19,085	$27,384	$46,758	$25,704	$25,638	$25,646	$25,712	$25,626	$25,611	$48,219	$336,615
5	Emission Monitoring - Peaking	($1,817)	$7,620	$8,513	$4,267	$16,907	$2,811	$2,777	$2,781	$2,814	$2,771	$2,763	$2,790	$54,997
5	Emission Monitoring - Intermediate	($1,217)	$5,102	$5,700	$2,857	$11,321	$13,882	$5,359	$8,862	$8,885	$8,855	$8,850	$8,868	$87,326
6	General Water Quality - Base	$13,513	$38,204	$44,253	$42,382	$17,620	$89,453	$85,703	$69,212	$100,023	$64,655	$96,016	$83,923	$744,957
6	General Water Quality - Peaking	$4,781	$8,018	$7,116	$7,151	$5,941	$15,552	$12,314	$12,325	$14,526	$12,298	$12,279	$14,463	$126,764
6	General Water Quality - Intermediate	$8,007	$39,138	$30,216	$18,132	$14,875	$27,913	$46,725	$15,753	$34,726	$16,735	$30,722	$17,185	$300,127
6	General Water Quality - Transmission	$4,036	$3,829	$4,662	$4,323	$3,997	$0	$0	$0	$31,000	$25,000	$25,000	$25,000	$126,847
7	Groundwater Contamination Investigation - Base	($34,003)	($34,003)	($34,003)	($34,003)	($34,003)	($34,003)	($34,003)	($34,003)	($34,003)	($34,003)	($34,003)	($34,003)	($408,036)
7	Groundwater Contamination Investigation - Distribution	$169,117	$101,459	$177,605	$101,758	$139,764	$194,378	$194,378	$211,088	$194,378	$300,868	$298,921	$341,379	$2,425,091
7	Groundwater Contamination Investigation - Transmission	$1,365	$1,256	$1,528	$1,443	$1,371	$19,319	$19,319	$23,051	$14,977	$28,607	$14,977	$38,508	$165,722
8	State NPDES Administration - Base	$1,303	$7,592	$1,696	$819	$516	$950	($10,975)	$950	$950	$950	$950	$23,950	$29,650
8	State NPDES Administration - Intermediate	$11,783	$5,165	$0	$3,770	$9,263	$0	($29,980)	$0	$0	$0	$0	$11,500	$11,500
10	Environmental Auditing/Assessment - Base	$0	($3,780)	$0	$0	$0	$1,917	$0	$0	$3,780	$9,998	$8,621	$0	$20,536
10	Environmental Auditing/Assessment - Intermediate	$0	($1,291)	$0	$0	$0	$655	$0	$0	$1,291	$3,416	$2,945	$0	$7,016
10	Environmental Auditing/Assessment - Peaking	$0	($1,929)	$0	$0	$0	$978	$0	$0	$1,929	$5,101	$4,399	$0	$10,478
11	General Solid & Hazardous Waste - Base	($7,400)	($7,400)	($7,400)	($7,400)	($7,400)	($7,400)	($7,400)	($7,400)	($7,400)	($7,400)	($7,400)	($7,400)	($88,800)
11	General Solid & Hazardous Waste - Base	$6,191	$13,036	$13,286	$6,746	$5,162	$26,772	$11,775	$11,796	$26,791	$13,095	$11,707	$29,146	$175,504
11	General Solid & Hazardous Waste - Peaking	$2,364	$4,184	$2,338	$1,768	$1,730	$4,747	$4,748	$4,759	$4,757	$5,422	$4,714	$4,694	$46,224
11	General Solid & Hazardous Waste - Intermediate	$1,119	$2,403	$1,165	$1,184	$1,158	$3,179	$3,180	$3,187	$3,185	$3,630	$3,156	$3,143	$29,688
11	General Solid & Hazardous Waste - Distribution	($13,813)	$48,354	$74,842	$33,994	$19,305	$60,000	$105,000	$105,000	$55,000	$55,000	$55,000	$55,000	$652,682
12	Above Ground Storage Tanks - Base	$3,754	$3,669	$4,156	$4,019	$3,808	$9,755	$3,946	$3,957	$18,954	$3,932	$3,913	$8,895	$72,759
12	Above Ground Storage Tanks - Peaking	$1,916	$1,872	$2,121	$2,051	$1,943	$2,426	$2,014	$2,019	$2,017	$2,006	$1,997	$1,987	$24,367
12	Above Ground Storage Tanks - Distribution	$0	($43,966)	$0	$0	$0	$50,000	$15,000	$50,000	$20,000	$0	$0	$0	$91,034
12	Above Ground Storage Tanks - Intermediate	$1,283	$1,253	$1,420	$1,373	$1,301	$1,624	$1,348	$1,352	$1,351	$61,343	$1,337	$1,331	$76,316
19	FDEP NOx Reduction Agreement - Base	($16,223)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($16,223)
20	Air Quality Compliance Program - Base	$928,283	$924,715	$940,726	$914,135	$1,064,021	$1,081,008	$831,601	$13,350,692	$497,328	$625,248	$481,692	$789,221	$22,428,670
22	Crist Water Conservation - Base	$9,701	$17,952	$876	$11,830	$17,091	$12,000	$27,000	$31,000	$33,000	$29,000	$40,000	$10,000	$239,450
23	Coal Combustion Residuals - Base	$44,254	$17,520	$25,227	$33,453	$34,790	$77,775	$178,071	$87,821	$89,807	$113,697	$80,673	$72,977	$856,066
23	Coal Combustion Residuals - Intermediate	$18,343	$25,418	$11,839	$19,093	$20,595	$45,590	$48,209	$37,834	$37,830	$47,618	$55,590	$174,692	$542,650
24	Smith Water Conservation - Intermediate	$9,356	$3,838	$309	$2,513	$0	$10,750	$3,000	$12,500	$16,250	$12,500	$12,500	$16,250	$99,765
27	Emission Allowances - Base	$0	$0	$0	$143,598	$8,948	$4	$5	$5	$4	$2	$2	$2	$152,570
27	Emission Allowances - Intermediate	$0	$0	$0	$5	$46	$0	$0	$0	$0	$0	$0	$0	$51
27	Emission Allowances - Peaking	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total	$1,181,020	$1,250,902	$1,436,842	$1,366,071	$1,430,625	$1,755,149	$1,568,915	$14,047,634	$1,329,799	$1,459,393	$1,257,747	$1,765,226	$29,849,324

ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE ACTUAL ESTIMATED
TRUE-UP AMOUNT FOR THE PERIOD

JANUARY 2021 THROUGH DECEMBER 2021
O&M ACTIVITIES

Project #	O&M Project/Strata	12-Month Total	Juris Factor	Juris 12 Month Amount	12 CP Demand	Energy	NCP Demand
2	Air Emission Fees - Intermediate	$16,454	97.5922%	$16,058		$16,058	
2	Air Emission Fees - Base	$209,409	100.0000%	$209,409		$209,409	
2	Air Emission Fees - Peaking	$4,343	76.0860%	$3,304		$3,304	
3	Title V - Base	$95,879	100.0000%	$95,879		$95,879	
3	Title V - Peaking	$48,919	76.0860%	$37,220		$37,220	
3	Title V - Intermediate	$50,454	97.5922%	$49,239		$49,239	
4	Asbestos Fees - Base	$500	100.0000%	$500	$500		
4	Asbestos Fees - Intermediate	$1,000	97.5922%	$976	$976		
5	Emission Monitoring - Base	$336,615	100.0000%	$336,615		$336,615	
5	Emission Monitoring - Peaking	$54,997	76.0860%	$41,845		$41,845	
5	Emission Monitoring - Intermediate	$87,326	97.5922%	$85,223		$85,223	
6	General Water Quality - Base	$744,957	100.0000%	$744,957	$744,957		
6	General Water Quality - Peaking	$126,764	76.0860%	$96,450	$96,450		
6	General Water Quality - Intermediate	$300,127	97.5922%	$292,901	$292,901		
6	General Water Quality - Transmission	$126,847	97.2343%	$123,339	$123,339		
7	Groundwater Contamination Investigation - Base	($408,036)	100.0000%	($408,036)	($408,036)		
7	Groundwater Contamination Investigation - Distribution	$2,425,091	98.1419%	$2,380,031			$2,380,031
7	Groundwater Contamination Investigation - Transmission	$165,722	97.2343%	$161,139	$161,139		
8	State NPDES Administration - Base	$29,650	100.0000%	$29,650	$29,650		
8	State NPDES Administration - Intermediate	$11,500	97.5922%	$11,223	$11,223		
10	Environmental Auditing/Assessment - Base	$20,536	100.0000%	$20,536	$20,536		
10	Environmental Auditing/Assessment - Intermediate	$7,016	97.5922%	$6,847	$6,847		
10	Environmental Auditing/Assessment - Peaking	$10,478	76.0860%	$7,972	$7,972		
11	General Solid & Hazardous Waste - Base	($88,800)	100.0000%	($88,800)	($88,800)		
11	General Solid & Hazardous Waste - Base	$175,504	100.0000%	$175,504	$175,504		
11	General Solid & Hazardous Waste - Peaking	$46,224	76.0860%	$35,170	$35,170		
11	General Solid & Hazardous Waste - Intermediate	$29,688	97.5922%	$28,973	$28,973		
11	General Solid & Hazardous Waste - Distribution	$652,682	98.1419%	$640,555			$640,555
12	Above Ground Storage Tanks - Base	$72,759	100.0000%	$72,759	$72,759		
12	Above Ground Storage Tanks - Peaking	$24,367	76.0860%	$18,540	$18,540		
12	Above Ground Storage Tanks - Distribution	$91,034	98.1419%	$89,343			$89,343
12	Above Ground Storage Tanks - Intermediate	$76,316	97.5922%	$74,479	$74,479		
19	FDEP NOx Reduction Agreement - Base	($16,223)	100.0000%	($16,223)		($16,223)	
20	Air Quality Compliance Program - Base	$22,428,670	100.0000%	$22,428,670		$22,428,670	
22	Crist Water Conservation - Base	$239,450	100.0000%	$239,450	$239,450		
23	Coal Combustion Residuals - Base	$856,066	100.0000%	$856,066	$856,066		
23	Coal Combustion Residuals - Intermediate	$542,650	97.5922%	$529,584	$529,584		
24	Smith Water Conservation - Intermediate	$99,765	97.5922%	$97,363	$97,363		
27	Emission Allowances - Base	$152,570	100.0000%	$152,570		$152,570	
27	Emission Allowances - Intermediate	$51	97.5922%	$50		$50	
27	Emission Allowances - Peaking	$0	76.0860%	$0		$0	
	Total	$29,849,324		$29,677,332	$3,127,543	$23,439,860	$3,109,928

JANUARY 2021 THROUGH DECEMBER 2021
O&M ACTIVITIES

	January Actual	February Actual	March Actual	April Actual	May Actual	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
2. Total of O&M Activities	$1,181,020	$1,250,902	$1,436,842	$1,366,071	$1,430,625	$1,755,149	$1,568,915	$14,047,634	$1,329,799	$1,459,393	$1,257,747	$1,765,226	$29,849,324
3. Recoverable Costs Jurisdictionalized on Energy - Base	$921,169	$976,295	$1,029,601	$1,095,598	$1,128,862	$1,117,484	$871,389	$13,387,131	$646,326	$664,891	$516,671	$851,502	$23,206,921
Recoverable Costs Jurisdictionalized on Energy - Intermediate	$1,551	$12,145	$26,665	$5,984	$22,811	$16,546	$9,177	$11,533	$11,553	$12,629	$11,035	$12,657	$154,285
Recoverable Costs Jurisdictionalized on Energy - Peaking	$1,331	$10,671	$16,324	$8,090	$20,126	$6,789	$8,478	$6,769	$6,800	$8,406	$6,026	$8,448	$108,258
Recoverable Costs Jurisdictionalized on 12 CP Demand - Trans.	$5,401	$5,085	$6,190	$5,766	$5,368	$19,319	$19,319	$23,051	$45,977	$53,607	$39,977	$63,508	$292,570
Recoverable Costs Jurisdictionalized on 12 CP Demand - Base	$37,314	$52,791	$48,090	$57,846	$37,584	$177,219	$254,617	$163,334	$231,901	$193,923	$200,478	$187,488	$1,642,587
Recoverable Costs Jurisdictionalized on 12 CP Demand - Interm.	$49,890	$75,922	$45,950	$46,065	$47,192	$89,711	$72,482	$70,625	$94,634	$145,242	$106,250	$224,100	$1,068,063
Recoverable Costs Jurisdictionalized on 12 CP Demand - Peaking	$9,061	$12,146	$11,575	$10,969	$9,614	$23,703	$19,076	$19,103	$23,229	$24,827	$23,388	$21,145	$207,834
Recoverable Costs Jurisdictionalized on NCP Demand - Dist.	$155,303	$105,847	$252,447	$135,752	$159,069	$304,378	$314,378	$366,088	$269,378	$355,868	$353,921	$396,379	$3,168,807
4. Retail Production Energy Jurisdictional Factor - Base	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	
Retail Production Energy Jurisdictional Factor - Intermediate	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	
Retail Production Energy Jurisdictional Factor - Peaking	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	
Retail Distribution Demand Jurisdictional Factor	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	
Retail Transmission Demand Jurisdictional Factor	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	
Retail Production Demand Jurisdictional Factor - Base	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	
Retail Production Demand Jurisdictional Factor - Intermediate	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	
Retail Production Demand Jurisdictional Factor - Peaking	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	
5. Jurisdictional Recoverable Costs- Transmission	$5,252	$4,945	$6,019	$5,607	$5,220	$18,785	$18,785	$22,414	$44,706	$52,125	$38,871	$61,752	$284,478
Jurisdictional Recoverable Costs - Production - Base	$958,483	$1,029,086	$1,077,691	$1,153,445	$1,166,446	$1,294,704	$1,126,006	$13,550,465	$878,228	$858,814	$717,150	$1,038,990	$24,849,507
Jurisdictional Recoverable Costs - Production - Intermediate	$50,203	$85,946	$70,867	$50,795	$68,317	$103,699	$79,692	$80,180	$103,631	$154,070	$114,461	$231,056	$1,192,916
Jurisdictional Recoverable Costs - Production - Peaking	$7,906	$17,360	$21,227	$14,502	$22,628	$23,200	$20,965	$19,685	$22,848	$25,286	$22,380	$22,516	$240,502
Jurisdictional Recoverable Costs - Distribution	$152,418	$103,880	$247,756	$133,230	$156,113	$298,722	$308,536	$359,286	$264,373	$349,256	$347,345	$389,014	$3,109,928
6. Total Jurisdictional Recoverable Costs for O&M	$1,174,261	$1,241,218	$1,423,560	$1,357,578	$1,418,723	$1,739,109	$1,553,984	$14,032,029	$1,313,784	$1,439,550	$1,240,207	$1,743,327	$29,677,332

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE ACTUAL ESTIMATED TRUE-UP AMOUNT FOR THE PERIOD

FORM 42-6E

JANUARY 2021 THROUGH DECEMBER 2021
VARIANCE REPORT OF CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

Capital Project	ECRC - 2021 Actual Estimated True Up [a]	ECRC 2021 Revised Projections [b]	$ Dif ECRC 2021 Projections [c]	% Dif ECRC 2021 Projections [d]
1 - Air Quality Assurance Testing	$16,218	$16,258	($39)	(0.2%)
2 - Crist 5, 6 & 7 Precipitator Projects	$2,621,304	$2,642,446	($21,142)	(0.8%)
3 - Crist 7 Flue Gas Conditioning	$102,230	$103,178	($948)	(0.9%)
4 - Low NOx Burners, Crist 6 & 7	$1,494,596	$1,682,106	($187,509)	(11.1%)
5 - CEMS - Plants Crist, & Daniel	$513,894	$516,870	($2,976)	(0.6%)
6 - Substation Contamination Remediation	$434,535	$459,629	($25,094)	(5.5%)
7 - Raw Water Well Flowmeters - Plants Crist & Smith	$12,141	$12,198	($57)	(0.5%)
8 - Crist Cooling Tower Cell	$36,269	$36,605	($336)	(0.9%)
9 - Crist Dechlorination System	$21,977	$22,040	($63)	(0.3%)
10 - Crist Diesel Fuel Oil Remediation	$1,073	$1,075	($2)	(0.2%)
11 - Crist Bulk Tanker Unload Sec Contain Struc	$2,624	$2,629	($6)	(0.2%)
12 - Crist IWW Sampling System	$2,651	$2,653	($3)	(0.1%)
13 - Sodium Injection System	$9,187	$9,272	($85)	(0.9%)
14 - Smith Stormwater Collection System	$156,019	$156,261	($242)	(0.2%)
15 - Smith Waste Water Treatment Facility	$81,876	$82,355	($479)	(0.6%)
16 - Daniel Ash Management Project	$1,201,630	$1,206,331	($4,701)	(0.4%)
17 - Smith Water Conservation	$2,255,150	$2,663,576	($408,426)	(15.3%)
19 - Crist FDEP Agreement for Ozone Attainment	$6,906,690	$6,925,431	($18,741)	(0.3%)
20 - SPCC Compliance	$71,794	$70,915	$878	1.2%
21 - Crist Common FTIR Monitor	$0	$0	$0	
22 - Precipitator Upgrades for CAM Compliance	$520,432	$525,258	($4,826)	(0.9%)
24 - Crist Water Conservation	$1,479,666	$1,487,765	($8,099)	(0.5%)
25 - Plant NPDES Permit Compliance Projects	$1,263,624	$1,203,324	$60,300	5.0%
26 - Air Quality Compliance Program	$101,587,778	$100,163,996	$1,423,782	1.4%
27 - General Water Quality	$1,038,849	$1,328,597	($289,748)	(21.8%)
28 - Coal Combustion Residual	$13,605,095	$15,320,788	($1,715,693)	(11.2%)
29 - Steam Electric Effluent Limitations Guidelines	$666,190	$734,326	($68,135)	(9.3%)
30 - 316(b) Cooling Water Intake Structure Regulation	$399,859	$493,620	($93,761)	(19.0%)
37 - Regulatory Asset Smith Units 1 & 2	$2,550,836	$2,549,055	$1,781	0.1%
Emission Allowances	$428,951	$437,756	($8,805)	(2.0%)
Total	$139,483,137	$140,856,312	($1,373,175)	(1.0%)

[a] The 12-Month Totals on Form 42-7E
[b] Approved in Order No. PSC-2021-0115-PAA-EI issued March 22,2021
[c] Column (2) - Column (3)
[d] Column (4) / Column (3)

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE ACTUAL ESTIMATED TRUE UP AMOUNT

JANUARY 2021 THROUGH DECEMBER 2021
CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

Capital Project	Strata	January Actual	February Actual	March Actual	April Actual	May Actual	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1-Air Quality Assurance Testing	Base	$1,383	$1,377	$1,371	$1,366	$1,360	$1,354	$1,349	$1,343	$1,337	$1,332	$1,326	$1,320	$16,218
2-Crist 5, 6 & 7 Precipitator Projects	Base	$219,331	$219,170	$219,008	$218,846	$218,685	$218,523	$218,361	$218,199	$218,038	$217,876	$217,714	$217,553	$2,621,304
3-Crist 7 Flue Gas Conditioning	Base	$8,519	$8,519	$8,519	$8,519	$8,519	$8,519	$8,519	$8,519	$8,519	$8,519	$8,519	$8,519	$102,230
4-Low NOx Burners, Crist 6 & 7	Base	$132,820	$124,661	$124,489	$124,316	$124,143	$123,971	$123,798	$123,625	$123,452	$123,280	$123,107	$122,934	$1,494,596
5-CEMS - Plants Crist & Daniel	Base	$43,298	$43,216	$43,127	$43,041	$42,954	$42,868	$42,781	$42,695	$42,608	$42,522	$42,435	$42,349	$513,894
6-Substation Contamination Remediation	Distribution	$29,349	$27,743	$27,694	$27,645	$29,225	$30,806	$30,785	$30,950	$31,341	$31,997	$32,533	$32,689	$362,757
6-Substation Contamination Remediation	Transmission	$6,465	$8,049	$8,046	$8,043	$6,464	$4,885	$4,883	$4,880	$4,877	$4,875	$4,872	$5,438	$71,778
7-Raw Water Flowmeters Plants Crist & Smith	Base	$756	$753	$750	$747	$744	$742	$739	$736	$733	$730	$727	$724	$8,881
7-Raw Water Flowmeters Plants Crist & Smith	Intermediate	$272	$272	$272	$272	$272	$272	$272	$272	$272	$272	$272	$272	$3,260
8-Crist Cooling Tower Cell	Base	$3,022	$3,022	$3,022	$3,022	$3,022	$3,022	$3,022	$3,022	$3,022	$3,022	$3,022	$3,022	$36,269
9-Crist Dechlorination System	Base	$1,871	$1,864	$1,857	$1,849	$1,842	$1,835	$1,828	$1,821	$1,813	$1,806	$1,799	$1,792	$21,977
10-Crist Diesel Fuel Oil Remediation	Base	$92	$91	$91	$90	$90	$90	$89	$89	$88	$88	$88	$87	$1,073
11-Crist Bulk Tanker Second Containment	Base	$224	$223	$222	$221	$220	$219	$218	$217	$216	$215	$214	$213	$2,624
12-Crist IWW Sampling System	Base	$227	$226	$225	$224	$223	$221	$220	$219	$218	$217	$216	$215	$2,651
13-Sodium Injection System	Base	$766	$766	$766	$766	$766	$766	$766	$766	$766	$766	$766	$766	$9,187
14-Smith Stormwater Collection System	Intermediate	$13,340	$13,278	$13,217	$13,155	$13,094	$13,032	$12,971	$12,909	$12,848	$12,786	$12,725	$12,663	$156,019
15-Smith Waste Water Treatment Facility	Intermediate	$6,902	$6,887	$6,873	$6,859	$6,845	$6,830	$6,816	$6,802	$6,787	$6,773	$6,759	$6,744	$81,876
16-Daniel Ash Management Project	Base	$101,255	$101,139	$100,879	$100,666	$100,454	$100,242	$100,030	$99,817	$99,605	$99,393	$99,181	$98,968	$1,201,630
17-Smith Water Conservation	Intermediate	$188,091	$187,591	$187,692	$188,105	$188,061	$187,800	$187,612	$187,423	$187,381	$187,485	$187,588	$190,320	$2,255,150
19-Crist Ozone Attainment	Base	$577,534	$576,489	$575,733	$574,964	$574,192	$573,418	$574,207	$576,495	$575,993	$576,151	$576,157	$575,356	$6,906,690
20-SPCC Compliance	Base	$5,688	$5,671	$5,654	$5,636	$5,619	$5,601	$5,584	$5,566	$5,549	$5,678	$5,952	$6,081	$68,279
20-SPCC Compliance	General	$189	$188	$187	$186	$185	$184	$183	$183	$182	$181	$180	$179	$2,206
20-SPCC Compliance	Intermediate	$111	$111	$110	$110	$110	$109	$109	$109	$108	$108	$108	$107	$1,308
21-Crist Common FTIR Monitor	Base	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
22-Precipitator Upgrades - CAM Compliance	Base	$43,369	$43,369	$43,369	$43,369	$43,369	$43,369	$43,369	$43,369	$43,369	$43,369	$43,369	$43,369	$520,432
24-Crist Water Conservation	Base	$124,884	$124,597	$124,310	$124,023	$123,736	$123,449	$123,162	$122,875	$122,588	$122,301	$122,014	$121,727	$1,479,666
25-Plant NPDES Permit Compliance	Base	$72,464	$72,350	$72,167	$71,979	$71,791	$71,731	$71,670	$71,480	$71,291	$71,101	$70,911	$70,721	$859,655
25-Plant NPDES Permit Compliance	Intermediate	$34,129	$34,044	$33,960	$33,875	$33,791	$33,706	$33,622	$33,537	$33,453	$33,368	$33,284	$33,199	$403,968
26-Air Quality Compliance Program	Base	$8,465,666	$8,456,041	$8,443,426	$8,432,611	$8,421,255	$8,410,346	$8,404,167	$8,398,675	$8,398,529	$8,415,690	$8,425,076	$8,428,450	$101,099,932
26-Air Quality Compliance Program	General	$0	$0	$0	$46	$61	$61	$61	$60	$60	$60	$60	$60	$529
26-Air Quality Compliance Program	Peaking	$2,318	$2,311	$2,304	$2,174	$2,071	$2,091	$2,084	$2,077	$2,070	$2,063	$2,057	$2,050	$25,670
26-Air Quality Compliance Program	Transmission	$38,925	$38,829	$38,748	$38,689	$38,591	$38,510	$38,429	$38,348	$38,267	$38,185	$38,104	$38,023	$461,647
27-General Water Quality	Base	$31,689	$64,689	$64,855	$86,136	$82,937	$83,527	$85,729	$89,003	$95,926	$106,491	$117,033	$130,834	$1,038,849
28-Coal Combustion Residuals	Base	$360,498	$566,163	$450,168	$486,300	$525,044	$537,677	$554,951	$571,181	$584,337	$598,860	$615,435	$685,399	$6,536,013
28-Coal Combustion Residuals	Intermediate	$512,851	$555,676	$554,245	$567,291	$577,811	$585,786	$595,074	$605,865	$619,145	$628,427	$631,763	$635,148	$7,069,082
29-Steam Electric Effluent Limitations	Base	$55,946	$56,248	$56,146	$56,067	$54,802	$53,562	$54,719	$55,876	$55,877	$55,799	$55,631	$55,517	$666,190
30-316b Cooling Water Intake Structure	Intermediate	$23,336	$22,692	$22,650	$30,319	$37,910	$37,825	$37,738	$37,652	$37,565	$37,478	$37,391	$37,304	$399,859
Regulatory Asset Smith Units 1 & 2	Intermediate	$215,265	$214,591	$213,917	$213,243	$212,570	$211,896	$211,559	$211,559	$211,559	$211,559	$211,559	$211,559	$2,550,836
Emission Allowances	Base	$35,749	$35,749	$35,749	$35,750	$35,748	$35,744	$35,744	$35,744	$35,744	$35,744	$35,744	$35,744	$428,951
		$11,358,593	$11,618,656	$11,485,819	$11,550,522	$11,588,574	$11,594,589	$11,617,219	$11,643,957	$11,675,535	$11,726,566	$11,765,689	$11,857,417	$139,483,137

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE ACTUAL ESTIMATED TRUE UP AMOUNT

JANUARY 2021 THROUGH DECEMBER 2021
CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

Capital Project	Strata	Monthly Data	Jurisdictionalization		Method of Classification		
		Twelve Month Total	Jurisdictional Factor	Juris Twelve Month Amount	Energy	12 CP Demand	NCP Demand
1-Air Quality Assurance Testing	Base	$16,218	100.0000%	$16,218	$1,248	$14,971	$0
2-Crist 5, 6 & 7 Precipitator Projects	Base	$2,621,304	100.0000%	$2,621,304	$201,639	$2,419,665	$0
3-Crist 7 Flue Gas Conditioning	Base	$102,230	100.0000%	$102,230	$7,864	$94,366	$0
4-Low NOx Burners, Crist 6 & 7	Base	$1,494,596	100.0000%	$1,494,596	$114,969	$1,379,627	$0
5-CEMS - Plants Crist & Daniel	Base	$513,894	100.0000%	$513,894	$39,530	$474,363	$0
6-Substation Contamination Remediation	Distribution	$362,757	98.1419%	$356,017	$0	$0	$356,017
6-Substation Contamination Remediation	Transmission	$71,778	97.2343%	$69,793	$5,369	$64,424	$0
7-Raw Water Flowmeters Plants Crist & Smith	Base	$8,881	100.0000%	$8,881	$683	$8,198	$0
7-Raw Water Flowmeters Plants Crist & Smith	Intermediate	$3,260	97.5922%	$3,181	$245	$2,937	$0
8-Crist Cooling Tower Cell	Base	$36,269	100.0000%	$36,269	$2,790	$33,479	$0
9-Crist Dechlorination System	Base	$21,977	100.0000%	$21,977	$1,691	$20,287	$0
10-Crist Diesel Fuel Oil Remediation	Base	$1,073	100.0000%	$1,073	$83	$990	$0
11-Crist Bulk Tanker Second Containment	Base	$2,624	100.0000%	$2,624	$202	$2,422	$0
12-Crist IWW Sampling System	Base	$2,651	100.0000%	$2,651	$204	$2,447	$0
13-Sodium Injection System	Base	$9,187	100.0000%	$9,187	$707	$8,480	$0
14-Smith Stormwater Collection System	Intermediate	$156,019	97.5922%	$152,263	$11,713	$140,550	$0
15-Smith Waste Water Treatment Facility	Intermediate	$81,876	97.5922%	$79,905	$6,147	$73,758	$0
16-Daniel Ash Management Project	Base	$1,201,630	100.0000%	$1,201,630	$92,433	$1,109,197	$0
17-Smith Water Conservation	Intermediate	$2,255,150	97.5922%	$2,200,851	$169,296	$2,031,555	$0
19-Crist Ozone Attainment	Base	$6,906,690	100.0000%	$6,906,690	$531,284	$6,375,406	$0
20-SPCC Compliance	Base	$68,279	100.0000%	$68,279	$5,252	$63,027	$0
20-SPCC Compliance	General	$2,206	96.9888%	$2,140	$165	$1,975	$0
20-SPCC Compliance	Intermediate	$1,308	97.5922%	$1,277	$98	$1,178	$0
21-Crist Common FTIR Monitor	Base	$0	100.0000%	$0	$0	$0	$0
22-Precipitator Upgrades - CAM Compliance	Base	$520,432	100.0000%	$520,432	$40,033	$480,398	$0
24-Crist Water Conservation	Base	$1,479,666	100.0000%	$1,479,666	$113,820	$1,365,846	$0
25-Plant NPDES Permit Compliance	Base	$859,655	100.0000%	$859,655	$66,127	$793,528	$0
25-Plant NPDES Permit Compliance	Intermediate	$403,968	97.5922%	$394,242	$30,326	$363,915	$0
26-Air Quality Compliance Program	Base	$101,099,932	100.0000%	$101,099,932	$7,776,918	$93,323,014	$0
26-Air Quality Compliance Program	General	$529	96.9888%	$513	$39	$473	$1
26-Air Quality Compliance Program	Peaking	$25,670	76.0860%	$19,531	$1,502	$18,029	$0
26-Air Quality Compliance Program	Transmission	$461,647	97.2343%	$448,879	$34,529	$414,350	$0
27-General Water Quality	Base	$1,038,849	100.0000%	$1,038,849	$79,911	$958,937	$0
28-Coal Combustion Residuals	Base	$6,536,013	100.0000%	$6,536,013	$502,770	$6,033,242	$0
28-Coal Combustion Residuals	Intermediate	$7,069,082	97.5922%	$6,898,875	$530,683	$6,368,192	$0
29-Steam Electric Effluent Limitations	Base	$666,190	100.0000%	$666,190	$51,245	$614,945	$0
30-316b Cooling Water Intake Structure	Intermediate	$399,859	97.5922%	$390,231	$30,018	$360,213	$0
Regulatory Asset Smith Units 1 & 2	Intermediate	$2,550,836	97.5922%	$2,489,418	$191,494	$2,297,924	$0
Emission Allowances	Base	$428,951	100.0000%	$428,951	$32,996	$395,955	$0
		$139,483,137		$139,144,306	$10,676,022	$128,112,267	$356,018

FORM: 42-7E-2

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE ACTUAL ESTIMATED TRUE UP AMOUNT

JANUARY 2021 THROUGH DECEMBER 2021
CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

	January Actual	February Actual	March Actual	April Actual	May Actual	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
2. Total of Capital Investment Projects	$11,358,593	$11,618,656	$11,485,819	$11,550,522	$11,588,574	$11,594,589	$11,617,219	$11,643,957	$11,675,535	$11,726,566	$11,765,689	$11,857,417	$139,483,137
3. Recoverable Costs Jurisdictionalized on 12 CP Demand - Trans.	$45,390	$46,878	$46,794	$46,732	$45,055	$43,395	$43,311	$43,228	$43,144	$43,060	$42,976	$43,462	$533,425
Recoverable Costs Jurisdictionalized on 12 CP Demand - Base	$10,287,051	$10,506,394	$10,375,904	$10,420,510	$10,441,515	$10,440,795	$10,455,022	$10,471,332	$10,489,621	$10,530,949	$10,566,437	$10,651,661	$125,637,190
Recoverable Costs Jurisdictionalized on 12 CP Demand - Inter.	$994,296	$1,035,143	$1,032,935	$1,053,229	$1,070,463	$1,077,257	$1,085,772	$1,096,128	$1,109,117	$1,118,256	$1,121,447	$1,127,316	$12,921,360
Recoverable Costs Jurisdictionalized on 12 CP Demand - Peaking	$2,318	$2,311	$2,304	$2,174	$2,071	$2,091	$2,084	$2,077	$2,070	$2,063	$2,057	$2,050	$25,670
Recoverable Costs Jurisdicitionalized on 12 CP Demand - General	$189	$188	$187	$232	$246	$245	$244	$243	$242	$241	$240	$239	$2,735
Recoverable Costs Jurisdictionalized on NCP Demand - Dist.	$29,349	$27,743	$27,694	$27,645	$29,225	$30,806	$30,785	$30,950	$31,341	$31,997	$32,533	$32,689	$362,757
4. Retail Transmission Demand Jurisdictional Factor	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	
Retail Production Demand Jurisdictional Factor - Base	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	
Retail Production Demand Jurisdictional Factor - Intermediate	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	
Retail Production Demand Jurisdictional Factor - Peaking	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	
Retail Production Demand Jurisdictional Factor - General	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%	
Retail Distribution Demand Jurisdictional Factor	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	
5. Jurisdictional Recoverable Costs - Transmission	$44,135	$45,582	$45,500	$45,440	$43,809	$42,195	$42,114	$42,032	$41,951	$41,869	$41,788	$42,260	$518,674
Jurisdictional Recoverable Costs - Production - Base	$10,287,051	$10,506,394	$10,375,904	$10,420,510	$10,441,515	$10,440,795	$10,455,022	$10,471,332	$10,489,621	$10,530,949	$10,566,437	$10,651,661	$125,637,190
Jurisdictional Recoverable Costs - Production - Intermediate	$970,356	$1,010,219	$1,008,065	$1,027,870	$1,044,688	$1,051,319	$1,059,629	$1,069,735	$1,082,412	$1,091,331	$1,094,446	$1,100,173	$12,610,243
Jurisdictional Recoverable Costs - Production - Peaking	$1,764	$1,758	$1,753	$1,654	$1,575	$1,591	$1,586	$1,580	$1,575	$1,570	$1,565	$1,560	$19,531
Jurisdictional Recoverable Costs - General	$183	$182	$181	$225	$239	$238	$237	$236	$235	$234	$233	$232	$2,653
Jurisdictional Recoverable Costs - Distribution	$28,803	$27,227	$27,179	$27,132	$28,682	$30,233	$30,213	$30,375	$30,759	$31,403	$31,928	$32,081	$356,017
6. Total Jurisdictional Recoverable Costs for Capital	$11,332,292	$11,591,362	$11,458,583	$11,522,830	$11,560,508	$11,566,372	$11,588,800	$11,615,290	$11,646,552	$11,697,355	$11,736,396	$11,827,966	$139,144,307

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8E

JANUARY 2021 THROUGH DECEMBER 2021
401-Air Quality Assurance Testing - Base

		Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments															
	a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
	f	Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
	g	Other														
2	Plant-in-Service/Depreciation Base (B		83,954	83,954	83,954	83,954	83,954	83,954	83,954	83,954	83,954	83,954	83,954	83,954	83,954	
3	Less: Accumulated Depreciation (C		(15,991)	(16,991)	(17,990)	(18,990)	(19,989)	(20,988)	(21,988)	(22,987)	(23,987)	(24,986)	(25,986)	(26,985)	(27,985)	
4	CWIP - Non Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A		67,963	66,963	65,964	64,964	63,965	62,965	61,966	60,967	59,967	58,968	57,968	56,969	55,969	
6	Average Net Investment			67,463	66,464	65,464	64,465	63,465	62,466	61,466	60,467	59,467	58,468	57,468	56,469	
7	Return on Average Net Investment															
	a	Equity Component (D)		334	329	324	319	314	309	304	299	294	289	285	280	3,682
	b	Debt Component		49	49	48	47	46	46	45	44	43	43	42	41	544
8	Investment Expenses															
	a	Depreciation (E)		999	999	999	999	999	999	999	999	999	999	999	999	11,993
	b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H			1,383	1,377	1,371	1,366	1,360	1,354	1,349	1,343	1,337	1,332	1,326	1,320	16,218

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicabl
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Remova
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this prograr
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8E

JANUARY 2021 THROUGH DECEMBER 2021
402-Crist 5, 6 & 7 Precipitator Projects - Base

		Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments															
	a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
	f	Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
	g	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B		8,538,323	8,538,323	8,538,323	8,538,323	8,538,323	8,538,323	8,538,323	8,538,323	8,538,323	8,538,323	8,538,323	8,538,323	8,538,323	
3	Less: Accumulated Depreciation (C		25,068,028	25,039,567	25,011,106	3,054,500	3,026,039	2,997,578	2,969,117	2,940,656	2,912,195	2,883,734	2,855,272	2,826,811	2,798,350	
4	CWIP - Non Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Capital Recovery Unamortized Balance (I		0	0	0	21,928,145	21,928,145	21,928,145	21,928,145	21,928,145	21,928,145	21,928,145	21,928,145	21,928,145	21,928,145	
6	Net Investment (Lines 2+3+4+5) (A		33,606,351	33,577,890	33,549,429	33,520,968	33,492,507	33,464,046	33,435,585	33,407,124	33,378,663	33,350,201	33,321,740	33,293,279	33,264,818	
7	Average Net Investment			33,592,121	33,563,660	33,535,198	33,506,737	33,478,276	33,449,815	33,421,354	33,392,893	33,364,432	33,335,971	33,307,510	33,279,049	
8	Return on Average Net Investment															
	a	Equity Component (D)		166,315	166,174	166,033	165,892	165,751	165,610	165,469	165,328	165,187	165,046	164,905	164,765	1,986,475
	b	Debt Component		24,556	24,535	24,514	24,493	24,473	24,452	24,431	24,410	24,389	24,369	24,348	24,327	293,297
9	Investment Expenses															
	a	Depreciation (E)		28,461	28,461	28,461	28,461	28,461	28,461	28,461	28,461	28,461	28,461	28,461	28,461	341,533
	b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Total System Recoverable Expenses (H			219,331	219,170	219,008	218,846	218,685	218,523	218,361	218,199	218,038	217,876	217,714	217,553	2,621,305

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicabl
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Remova
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this prograr
(H) Line 7 + 8
(I) Regulatory assets approved by Order No. PSC-2021-0115-PAA-EI, issued March 22, 202

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8E

JANUARY 2021 THROUGH DECEMBER 2021
403-Crist 7 Flue Gas Conditioning - Base

Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1 Investments														
a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b Clearings to Plan		0	0	0	0	0	0	0	0	0	0	0	0	0
c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
f Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
g Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2 Plant-in-Service/Depreciation Base (B	0	0	0	0	0	0	0	0	0	0	0	0	0	
3 Less: Accumulated Depreciation (C	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	
4 CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2+3+4) (A	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	
6 Average Net Investmen		1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	
7 Return on Average Net Investmen														
a Equity Component (D)		7,423	7,423	7,423	7,423	7,423	7,423	7,423	7,423	7,423	7,423	7,423	7,423	89,078
b Debt Component		1,096	1,096	1,096	1,096	1,096	1,096	1,096	1,096	1,096	1,096	1,096	1,096	13,152
8 Investment Expenses														
a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (H		8,519	8,519	8,519	8,519	8,519	8,519	8,519	8,519	8,519	8,519	8,519	8,519	102,230

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicabl
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Remova
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this prograr
(H) Line 7 + 8

FORM: 42-8E

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2021 THROUGH DECEMBER 2021
404-Low NOx Burners, Crist 6 & 7 - Base

	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Retirements		(4,778,014)	0	0	0	0	0	0	0	0	0	0	0	(4,778,014)
d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
f	Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
g	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B	13,527,932	8,749,918	8,749,918	8,749,918	8,749,918	8,749,918	8,749,918	8,749,918	8,749,918	8,749,918	8,749,918	8,749,918	8,749,918	
3	Less: Accumulated Depreciation (C	3,115,359	7,855,011	7,824,612	7,794,213	7,763,815	7,733,416	7,703,018	7,672,619	7,642,220	7,611,822	7,581,423	7,551,025	7,520,626	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A	16,643,291	16,604,929	16,574,530	16,544,131	16,513,733	16,483,334	16,452,936	16,422,537	16,392,138	16,361,740	16,331,341	16,300,943	16,270,544	
6	Average Net Investment		16,624,110	16,589,729	16,559,331	16,528,932	16,498,534	16,468,135	16,437,736	16,407,338	16,376,939	16,346,541	16,316,142	16,285,743	
7	Return on Average Net Investment														
a	Equity Component (D)		82,306	82,136	81,985	81,835	81,684	81,534	81,383	81,233	81,082	80,932	80,781	80,631	977,522
b	Debt Component		12,152	12,127	12,105	12,083	12,060	12,038	12,016	11,994	11,972	11,949	11,927	11,905	144,328
8	Investment Expenses														
a	Depreciation (E)		38,362	30,399	30,399	30,399	30,399	30,399	30,399	30,399	30,399	30,399	30,399	30,399	372,747
b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H		132,820	124,661	124,489	124,316	124,143	123,971	123,798	123,625	123,452	123,280	123,107	122,934	1,494,596

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicabl
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Remova
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this prograr
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8E

JANUARY 2021 THROUGH DECEMBER 2021
405-CEMS - Plants Crist & Daniel - Base

		Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments															
	a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
	f	Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
	g	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)		4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	
3	Less: Accumulated Depreciation (C)		83,961	68,745	53,528	38,311	23,095	7,878	(7,338)	(22,555)	(37,772)	(52,988)	(68,205)	(83,422)	(98,638)	
4	CWIP - Non Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)		4,796,744	4,781,528	4,766,311	4,751,094	4,735,878	4,720,661	4,705,444	4,690,228	4,675,011	4,659,795	4,644,578	4,629,361	4,614,145	
6	Average Net Investment			4,789,136	4,773,919	4,758,703	4,743,486	4,728,269	4,713,053	4,697,836	4,682,620	4,667,403	4,652,186	4,636,970	4,621,753	
7	Return on Average Net Investment															
	a	Equity Component (D)		23,711	23,636	23,560	23,485	23,410	23,334	23,259	23,184	23,108	23,033	22,958	22,882	279,560
	b	Debt Component		3,501	3,490	3,479	3,467	3,456	3,445	3,434	3,423	3,412	3,401	3,390	3,379	41,276
8	Investment Expenses															
	a	Depreciation (E)		15,217	15,217	15,217	15,217	15,217	15,217	15,217	15,217	15,217	15,217	15,217	15,217	182,599
	b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Property Taxes		870	874	872	872	872	872	872	872	872	872	872	872	10,458
	e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)			43,298	43,216	43,127	43,041	42,954	42,868	42,781	42,695	42,608	42,522	42,435	42,349	513,894

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this program
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8E

JANUARY 2021 THROUGH DECEMBER 2021
406-Substation Contamination Remediation - Distributio

	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
a	Expenditures/Additions		(548,161)	0	0	0	573,387	0	10,000	65,000	90,000	90,000	47,790	10,000	338,016
b	Clearings to Plant		0	0	0	0	0	0	0	0	0	150,000	0	33,274	183,274
c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
f	Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
g	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B	3,547,349	3,547,349	3,547,349	3,547,349	3,547,349	3,547,349	3,547,349	3,547,349	3,547,349	3,547,349	3,697,349	3,697,349	3,730,623	
3	Less: Accumulated Depreciation (C	378,797	370,220	361,644	353,068	344,491	335,915	327,339	318,762	310,186	301,610	292,839	283,875	274,868	
4	CWIP - Non Interest Bearing	8,048	(540,113)	(540,113)	(540,113)	(540,113)	33,274	33,274	43,274	108,274	198,274	138,274	186,064	162,790	
5	Net Investment (Lines 2+3+4) (A	3,934,194	3,377,456	3,368,880	3,360,304	3,351,727	3,916,538	3,907,961	3,909,385	3,965,809	4,047,232	4,128,462	4,167,288	4,168,280	
6	Average Net Investment		3,655,825	3,373,168	3,364,592	3,356,015	3,634,132	3,912,249	3,908,673	3,937,597	4,006,520	4,087,847	4,147,875	4,167,784	
7	Return on Average Net Investmen														
a	Equity Component (D)		18,100	16,701	16,658	16,616	17,993	19,370	19,352	19,495	19,836	20,239	20,536	20,635	225,529
b	Debt Component		2,672	2,466	2,460	2,453	2,657	2,860	2,857	2,878	2,929	2,988	3,032	3,047	33,299
8	Investment Expenses														
a	Depreciation (E)		8,576	8,576	8,576	8,576	8,576	8,576	8,576	8,576	8,576	8,770	8,964	9,007	103,929
b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H		29,349	27,743	27,694	27,645	29,225	30,806	30,785	30,950	31,341	31,997	32,533	32,689	362,757

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicabl
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Remova
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this prograr
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8E

JANUARY 2021 THROUGH DECEMBER 2021
406-Substation Contamination Remediation - Transmissio

		Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments															
	a	Expenditures/Additions		558,338	0	0	0	(554,803)	0	0	0	0	0	0	0	3,535
	b	Clearings to Plan		0	0	0	0	0	0	0	0	0	0	0	489,301	489,301
	c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
	f	Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
	g	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B		339,156	339,156	339,156	339,156	339,156	339,156	339,156	339,156	339,156	339,156	339,156	339,156	828,456	
3	Less: Accumulated Depreciation (C		(50,558)	(51,038)	(51,519)	(51,999)	(52,480)	(52,960)	(53,441)	(53,921)	(54,401)	(54,882)	(55,362)	(55,843)	(56,894)	
4	CWIP - Non Interest Bearing		485,766	1,044,103	1,044,103	1,044,103	1,044,103	489,301	489,301	489,301	489,301	489,301	489,301	489,301	0	
5	Net Investment (Lines 2+3+4) (A		774,364	1,332,221	1,331,741	1,331,260	1,330,780	775,496	775,016	774,535	774,055	773,574	773,094	772,614	771,562	
6	Average Net Investment			1,053,293	1,331,981	1,331,501	1,331,020	1,053,138	775,256	774,776	774,295	773,815	773,334	772,854	772,088	
7	Return on Average Net Investmen															
	a	Equity Component (D)		5,215	6,595	6,592	6,590	5,214	3,838	3,836	3,834	3,831	3,829	3,826	3,823	57,022
	b	Debt Component		770	974	973	973	770	567	566	566	566	565	565	564	8,419
8	Investment Expenses															
	a	Depreciation (E)		480	480	480	480	480	480	480	480	480	480	480	1,051	6,337
	b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H			6,465	8,049	8,046	8,043	6,464	4,885	4,883	4,880	4,877	4,875	4,872	5,438	71,778

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicabl
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Remova
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this progran
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8E

JANUARY 2021 THROUGH DECEMBER 2021
407-Raw Water Well Flowmeters Plants Crist & Smith - Base

	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
f	Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
g	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	
3	Less: Accumulated Depreciation (C	(104,668)	(105,168)	(105,668)	(106,168)	(106,668)	(107,167)	(107,667)	(108,167)	(108,667)	(109,167)	(109,667)	(110,166)	(110,666)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A	45,281	44,781	44,282	43,782	43,282	42,782	42,282	41,782	41,283	40,783	40,283	39,783	39,283	
6	Average Net Investment		45,031	44,532	44,032	43,532	43,032	42,532	42,032	41,533	41,033	40,533	40,033	39,533	
7	Return on Average Net Investment														
a	Equity Component (D)		223	220	218	216	213	211	208	206	203	201	198	196	2,512
b	Debt Component		33	33	32	32	31	31	31	30	30	30	29	29	371
8	Investment Expenses														
a	Depreciation (E)		500	500	500	500	500	500	500	500	500	500	500	500	5,998
b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H		756	753	750	747	744	742	739	736	733	730	727	724	8,881

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicabl
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Remova
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this prograr
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8E

JANUARY 2021 THROUGH DECEMBER 2021
407-Raw Water Well Flowmeters Plants Crist & Smith - Intermediate

		Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments															
	a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
	f	Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
	g	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B		0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C		47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	
4	CWIP - Non Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A		47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	
6	Average Net Investment			47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	
7	Return on Average Net Investment															
	a	Equity Component (D)		237	237	237	237	237	237	237	237	237	237	237	237	2,841
	b	Debt Component		35	35	35	35	35	35	35	35	35	35	35	35	419
8	Investment Expenses															
	a	Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H			272	272	272	272	272	272	272	272	272	272	272	272	3,260

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicabl
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Remova
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this prograr
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2021 THROUGH DECEMBER 2021
408-Crist Cooling Tower Cell - Base

Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1 Investments														
a Expenditures/Addition		0	0	0	0	0	0	0	0	0	0	0	0	0
b Clearings to Plan		0	0	0	0	0	0	0	0	0	0	0	0	0
c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
f Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
g Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2 Plant-in-Service/Depreciation Base (B	0	0	0	0	0	0	0	0	0	0	0	0	0	
3 Less: Accumulated Depreciation (C	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	
4 CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2+3+4) (A	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	
6 Average Net Investmen		531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	
7 Return on Average Net Investmen														
a Equity Component (D)		2,634	2,634	2,634	2,634	2,634	2,634	2,634	2,634	2,634	2,634	2,634	2,634	31,603
b Debt Component		389	389	389	389	389	389	389	389	389	389	389	389	4,666
8 Investment Expenses														
a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (H		3,022	3,022	3,022	3,022	3,022	3,022	3,022	3,022	3,022	3,022	3,022	3,022	36,269

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicabl
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Remova
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this prograr
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8E

JANUARY 2021 THROUGH DECEMBER 2021
409-Crist Dechlorination System - Base

		Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments															
	a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
	f	Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
	g	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B		380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	
3	Less: Accumulated Depreciation (C		(274,097)	(275,366)	(276,635)	(277,904)	(279,173)	(280,442)	(281,711)	(282,980)	(284,249)	(285,518)	(286,787)	(288,056)	(289,325)	
4	CWIP - Non Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A		106,600	105,331	104,062	102,793	101,524	100,255	98,986	97,717	96,448	95,179	93,910	92,641	91,372	
6	Average Net Investment			105,966	104,697	103,428	102,159	100,890	99,621	98,352	97,083	95,814	94,545	93,276	92,007	
7	Return on Average Net Investment															
	a	Equity Component (D)		525	518	512	506	500	493	487	481	474	468	462	456	5,881
	b	Debt Component		77	77	76	75	74	73	72	71	70	69	68	67	868
8	Investment Expenses															
	a	Depreciation (E)		1,269	1,269	1,269	1,269	1,269	1,269	1,269	1,269	1,269	1,269	1,269	1,269	15,228
	b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H			1,871	1,864	1,857	1,849	1,842	1,835	1,828	1,821	1,813	1,806	1,799	1,792	21,977

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicabl
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Remova
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this prograr
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8E

JANUARY 2021 THROUGH DECEMBER 2021
410-Crist Diesel Fuel Oil Remediation - Base

	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
f	Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
g	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B	20,968	20,968	20,968	20,968	20,968	20,968	20,968	20,968	20,968	20,968	20,968	20,968	20,968	
3	Less: Accumulated Depreciation (C	(17,119)	(17,189)	(17,259)	(17,329)	(17,398)	(17,468)	(17,538)	(17,608)	(17,678)	(17,748)	(17,818)	(17,888)	(17,958)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A	3,849	3,779	3,709	3,639	3,569	3,499	3,429	3,360	3,290	3,220	3,150	3,080	3,010	
6	Average Net Investment		3,814	3,744	3,674	3,604	3,534	3,464	3,394	3,325	3,255	3,185	3,115	3,045	
7	Return on Average Net Investment														
a	Equity Component (D)		19	19	18	18	17	17	17	16	16	16	15	15	204
b	Debt Component		3	3	3	3	3	3	2	2	2	2	2	2	30
8	Investment Expenses														
a	Depreciation (E)		70	70	70	70	70	70	70	70	70	70	70	70	839
b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H		92	91	91	90	90	90	89	89	88	88	88	87	1,073

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicabl
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Remova
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this prograr
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8E

JANUARY 2021 THROUGH DECEMBER 2021
411-Crist Bulk Tanker Unloading Second Containment - Base

Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1 Investments														
a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
f Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
g Other (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
2 Plant-in-Service/Depreciation Base (B	50,748	50,748	50,748	50,748	50,748	50,748	50,748	50,748	50,748	50,748	50,748	50,748	50,748	
3 Less: Accumulated Depreciation (C	(41,024)	(41,193)	(41,362)	(46,605)	(46,774)	(46,943)	(47,112)	(47,281)	(47,450)	(47,620)	(47,789)	(47,958)	(48,127)	
4 CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Capital Recovery Unamortized Balance	0	0	0	5,073	5,073	5,073	5,073	5,073	5,073	5,073	5,073	5,073	5,073	
6 Net Investment (Lines 2+3+4+5) (A	9,724	9,554	9,385	9,216	9,047	8,878	8,709	8,540	8,370	8,201	8,032	7,863	7,694	
7 Average Net Investment		9,639	9,470	9,301	9,132	8,962	8,793	8,624	8,455	8,286	8,117	7,947	7,778	
8 Return on Average Net Investment														
a Equity Component (D)		48	47	46	45	44	44	43	42	41	40	39	39	517
b Debt Component		7	7	7	7	7	6	6	6	6	6	6	6	76
9 Investment Expenses														
a Depreciation (E)		169	169	169	169	169	169	169	169	169	169	169	169	2,030
b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
10 Total System Recoverable Expenses (H		224	223	222	221	220	219	218	217	216	215	214	213	2,624

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicabl
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Remova
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this prograr
(H) Line 8 + 9
(I) Regulatory assets approved by Order No. PSC-2021-0115-PAA-EI, issued March 22, 202

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8E

JANUARY 2021 THROUGH DECEMBER 2021
412-Crist IWW Sampling System - Base

Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1 Investments														
a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
f Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
g Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2 Plant-in-Service/Depreciation Base (B	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	
3 Less: Accumulated Depreciation (C	(54,405)	(54,603)	(54,802)	(55,000)	(55,199)	(55,397)	(55,596)	(55,794)	(55,993)	(56,191)	(56,390)	(56,588)	(56,787)	
4 CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2+3+4) (A	5,138	4,939	4,741	4,542	4,344	4,146	3,947	3,749	3,550	3,352	3,153	2,955	2,756	
6 Average Net Investment		5,039	4,840	4,642	4,443	4,245	4,046	3,848	3,649	3,451	3,252	3,054	2,855	
7 Return on Average Net Investment														
a Equity Component (D)		25	24	23	22	21	20	19	18	17	16	15	14	235
b Debt Component		4	4	3	3	3	3	3	3	3	2	2	2	35
8 Investment Expenses														
a Depreciation (E)		198	198	198	198	198	198	198	198	198	198	198	198	2,382
b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (H		227	226	225	224	223	221	220	219	218	217	216	215	2,651

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicabl
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Remova
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this prograr
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8E

JANUARY 2021 THROUGH DECEMBER 2021
413-Sodium Injection System - Base

	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
f	Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
g	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C	134,738	134,738	134,738	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Capital Recovery Unamortized Balance	0	0	0	134,738	134,738	134,738	134,738	134,738	134,738	134,738	134,738	134,738	134,738	
6	Net Investment (Lines 2+3+4+5) (A	134,738	134,738	134,738	134,738	134,738	134,738	134,738	134,738	134,738	134,738	134,738	134,738	134,738	
7	Average Net Investment		134,738	134,738	134,738	134,738	134,738	134,738	134,738	134,738	134,738	134,738	134,738	134,738	
8	Return on Average Net Investment														
a	Equity Component (D)		667	667	667	667	667	667	667	667	667	667	667	667	8,005
b	Debt Component		98	98	98	98	98	98	98	98	98	98	98	98	1,182
9	Investment Expenses														
a	Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Total System Recoverable Expenses (H		766	766	766	766	766	766	766	766	766	766	766	766	9,187

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicabl
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Remova
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this prograr
(H) Line 8 + 9
(I) Regulatory assets approved by Order No. PSC-2021-0115-PAA-EI, issued March 22, 202

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2021 THROUGH DECEMBER 2021
414-Smith Stormwater Collection System - Intermediate

	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
f	Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
g	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	
3	Less: Accumulated Depreciation (C	(2,316,721)	(2,327,548)	(2,338,375)	(2,349,202)	(2,360,030)	(2,370,857)	(2,381,684)	(2,392,511)	(2,403,338)	(2,414,165)	(2,424,992)	(2,435,820)	(2,446,647)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A	447,658	436,831	426,003	415,176	404,349	393,522	382,695	371,868	361,040	350,213	339,386	328,559	317,732	
6	Average Net Investment		442,244	431,417	420,590	409,763	398,935	388,108	377,281	366,454	355,627	344,800	333,973	323,145	
7	Return on Average Net Investment														
a	Equity Component (D)		2,190	2,136	2,082	2,029	1,975	1,922	1,868	1,814	1,761	1,707	1,653	1,600	22,737
b	Debt Component		323	315	307	300	292	284	276	268	260	252	244	236	3,357
8	Investment Expenses														
a	Depreciation (E)		10,827	10,827	10,827	10,827	10,827	10,827	10,827	10,827	10,827	10,827	10,827	10,827	129,926
b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H		13,340	13,278	13,217	13,155	13,094	13,032	12,971	12,909	12,848	12,786	12,725	12,663	156,019

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicabl
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Remova
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this prograr
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8E

JANUARY 2021 THROUGH DECEMBER 2021
415-Smith Waste Water Treatment Facility - Intermediate

	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
f	Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
g	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	643,620	643,620	643,620	643,620	643,620	643,620	643,620	643,620	643,620	643,620	643,620	643,620	643,620	
3	Less: Accumulated Depreciation (C)	128,665	126,144	123,623	121,103	118,582	116,061	113,540	111,019	108,498	105,977	103,457	100,936	98,415	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	772,285	769,764	767,243	764,722	762,201	759,680	757,160	754,639	752,118	749,597	747,076	744,555	742,035	
6	Average Net Investment		771,024	768,503	765,983	763,462	760,941	758,420	755,899	753,378	750,857	748,337	745,816	743,295	
7	Return on Average Net Investment														
a	Equity Component (D)		3,817	3,805	3,792	3,780	3,767	3,755	3,742	3,730	3,717	3,705	3,693	3,680	44,984
b	Debt Component		564	562	560	558	556	554	553	551	549	547	545	543	6,642
8	Investment Expenses														
a	Depreciation (E)		2,521	2,521	2,521	2,521	2,521	2,521	2,521	2,521	2,521	2,521	2,521	2,521	30,250
b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		6,902	6,887	6,873	6,859	6,845	6,830	6,816	6,802	6,787	6,773	6,759	6,744	81,876

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this program
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8E

JANUARY 2021 THROUGH DECEMBER 2021
416-Daniel Ash Management Project - Base

		Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments															
	a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
	f	Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
	g	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B		14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	
3	Less: Accumulated Depreciation (C		(7,281,286)	(7,318,641)	(7,355,996)	(7,393,351)	(7,430,705)	(7,468,060)	(7,505,415)	(7,542,770)	(7,580,125)	(7,617,480)	(7,654,835)	(7,692,190)	(7,729,545)	
4	CWIP - Non Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A		7,658,275	7,620,920	7,583,565	7,546,211	7,508,856	7,471,501	7,434,146	7,396,791	7,359,436	7,322,081	7,284,726	7,247,371	7,210,016	
6	Average Net Investment			7,639,598	7,602,243	7,564,888	7,527,533	7,490,178	7,452,823	7,415,468	7,378,113	7,340,758	7,303,404	7,266,049	7,228,694	
7	Return on Average Net Investment															
	a	Equity Component (D)		37,824	37,639	37,454	37,269	37,084	36,899	36,714	36,529	36,344	36,159	35,974	35,789	441,677
	b	Debt Component		5,585	5,557	5,530	5,503	5,475	5,448	5,421	5,393	5,366	5,339	5,311	5,284	65,212
8	Investment Expenses															
	a	Depreciation (E)		37,355	37,355	37,355	37,355	37,355	37,355	37,355	37,355	37,355	37,355	37,355	37,355	448,259
	b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Property Taxes		20,492	20,588	20,540	20,540	20,540	20,540	20,540	20,540	20,540	20,540	20,540	20,540	246,481
	e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H			101,255	101,139	100,879	100,666	100,454	100,242	100,030	99,817	99,605	99,393	99,181	98,968	1,201,630

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicabl
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Remova
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this prograr
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8E

JANUARY 2021 THROUGH DECEMBER 2021
417-Smith Water Conservation - Intermediate

		Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments															
	a	Expenditures/Additions		(24,558)	17,621	186,807	127,714	26,019	51,400	51,400	51,400	102,800	102,800	102,800	1,028,000	1,824,203
	b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
	f	Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
	g	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B		21,590,761	21,590,761	21,590,761	21,590,761	21,590,761	21,590,761	21,590,761	21,590,761	21,590,761	21,590,761	21,590,761	21,590,761	21,590,761	
3	Less: Accumulated Depreciation (C		(3,484,846)	(3,569,409)	(3,653,973)	(3,738,537)	(3,823,101)	(3,907,665)	(3,992,229)	(4,076,792)	(4,161,356)	(4,245,920)	(4,330,484)	(4,415,048)	(4,499,611)	
4	CWIP - Non Interest Bearing		168,933	144,375	161,996	348,803	476,517	502,536	553,936	605,336	656,736	759,536	862,336	965,136	1,993,136	
5	Net Investment (Lines 2+3+4) (A		18,274,848	18,165,726	18,098,783	18,201,027	18,244,178	18,185,632	18,152,469	18,119,305	18,086,141	18,104,377	18,122,613	18,140,849	19,084,286	
6	Average Net Investment			18,220,287	18,132,255	18,149,905	18,222,602	18,214,905	18,169,050	18,135,887	18,102,723	18,095,259	18,113,495	18,131,731	18,612,568	
7	Return on Average Net Investmen															
	a	Equity Component (D)		90,209	89,773	89,860	90,220	90,182	89,955	89,791	89,627	89,590	89,680	89,770	92,151	1,080,807
	b	Debt Component		13,319	13,255	13,268	13,321	13,315	13,282	13,257	13,233	13,228	13,241	13,254	13,606	159,578
8	Investment Expenses															
	a	Depreciation (E)		84,564	84,564	84,564	84,564	84,564	84,564	84,564	84,564	84,564	84,564	84,564	84,564	1,014,766
	b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H			188,091	187,591	187,692	188,105	188,061	187,800	187,612	187,423	187,381	187,485	187,588	190,320	2,255,150

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicabl
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Remova
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this prograr
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8E

JANUARY 2021 THROUGH DECEMBER 2021
419-Crist FDEP Agreement for Ozone Attainment - Base

Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1 Investments														
a Expenditures/Additions		0	5,757	1,214	892	415	0	241,580	51,400	51,400	51,400	0	0	404,059
b Clearings to Plant		0	0	0	0	0	0	262,409	0	0	395,780	0	0	658,189
c Retirements		(170,831)	0	0	0	0	0	0	0	0	0	0	0	(170,831)
d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
f Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
g Other (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
2 Plant-in-Service/Depreciation Base (B)	39,088,012	38,917,181	38,917,181	38,917,181	38,917,181	38,917,181	38,917,181	39,179,590	39,179,590	39,179,590	39,575,370	39,575,370	39,575,370	
3 Less: Accumulated Depreciation (C)	38,295,733	38,329,780	38,193,280	(13,024,200)	(13,160,700)	(13,297,199)	(13,433,699)	(13,571,079)	(13,710,702)	(13,850,325)	(13,990,609)	(14,131,552)	(14,272,495)	
4 CWIP - Non Interest Bearing	254,131	254,131	259,888	261,102	261,994	262,409	262,409	241,580	292,980	344,380	0	0	0	
5 Capital Recovery Unamortized Balance	0	0	0	51,080,981	51,080,981	51,080,981	51,080,981	51,080,981	51,080,981	51,080,981	51,080,981	51,080,981	51,080,981	
6 Net Investment (Lines 2+3+4+5) (A)	77,637,876	77,501,092	77,370,349	77,235,064	77,099,456	76,963,372	76,826,873	76,931,072	76,842,849	76,754,626	76,665,743	76,524,800	76,383,857	
7 Average Net Investment		77,569,484	77,435,720	77,302,707	77,167,260	77,031,414	76,895,122	76,878,972	76,886,961	76,798,738	76,710,184	76,595,271	76,454,328	
8 Return on Average Net Investment														
a Equity Component (D)		384,047	383,384	382,726	382,055	381,383	380,708	380,628	380,667	380,231	379,792	379,223	378,525	4,573,368
b Debt Component		56,703	56,606	56,508	56,409	56,310	56,210	56,199	56,204	56,140	56,075	55,991	55,888	675,244
9 Investment Expenses														
a Depreciation (E)		136,784	136,499	136,499	136,499	136,499	136,499	137,380	139,623	139,623	140,283	140,943	140,943	1,658,078
b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
10 Total System Recoverable Expenses (H)		577,534	576,489	575,733	574,964	574,192	573,418	574,207	576,495	575,993	576,151	576,157	575,356	6,906,690

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this program
(H) Line 8 + 9
(I) Regulatory assets approved by Order No. PSC-2021-0115-PAA-EI, issued March 22, 2021

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8E

JANUARY 2021 THROUGH DECEMBER 2021
420-SPCC Compliance - Base

	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	51,400	51,400	0	102,800
b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
f	Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
g	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B	919,836	919,836	919,836	919,836	919,836	919,836	919,836	919,836	919,836	919,836	919,836	919,836	919,836	
3	Less: Accumulated Depreciation (C	(456,794)	(459,860)	(462,926)	(465,992)	(469,058)	(472,125)	(475,191)	(478,257)	(481,323)	(484,389)	(487,455)	(490,521)	(493,587)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	51,400	102,800	102,800	
5	Net Investment (Lines 2+3+4) (A	463,042	459,975	456,909	453,843	450,777	447,711	444,645	441,579	438,513	435,447	483,780	532,114	529,048	
6	Average Net Investment		461,509	458,442	455,376	452,310	449,244	446,178	443,112	440,046	436,980	459,613	507,947	530,581	
7	Return on Average Net Investment														
a	Equity Component (D)		2,285	2,270	2,255	2,239	2,224	2,209	2,194	2,179	2,163	2,276	2,515	2,627	27,435
b	Debt Component		337	335	333	331	328	326	324	322	319	336	371	388	4,051
8	Investment Expenses														
a	Depreciation (E)		3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	36,793
b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H		5,688	5,671	5,654	5,636	5,619	5,601	5,584	5,566	5,549	5,678	5,952	6,081	68,279

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicabl
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Remova
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this prograr
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8E

JANUARY 2021 THROUGH DECEMBER 2021
420-SPCC Compliance - General

		Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments															
	a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
	f	Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
	g	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B		13,195	13,195	13,195	13,195	13,195	13,195	13,195	13,195	13,195	13,195	13,195	13,195	13,195	
3	Less: Accumulated Depreciation (C		(7,540)	(7,697)	(7,854)	(8,011)	(8,168)	(8,325)	(8,482)	(8,639)	(8,796)	(8,954)	(9,111)	(9,268)	(9,425)	
4	CWIP - Non Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A		5,655	5,498	5,341	5,184	5,026	4,869	4,712	4,555	4,398	4,241	4,084	3,927	3,770	
6	Average Net Investment			5,576	5,419	5,262	5,105	4,948	4,791	4,634	4,477	4,320	4,163	4,005	3,848	
7	Return on Average Net Investment															
	a	Equity Component (D)		28	27	26	25	24	24	23	22	21	21	20	19	280
	b	Debt Component		4	4	4	4	4	4	3	3	3	3	3	3	41
8	Investment Expenses															
	a	Depreciation (E)		157	157	157	157	157	157	157	157	157	157	157	157	1,885
	b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H			189	188	187	186	185	184	183	183	182	181	180	179	2,206

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicabl
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Remova
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this prograr
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8E

JANUARY 2021 THROUGH DECEMBER 2021
420-SPCC Compliance - Intermediate

		Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments															
	a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
	f	Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
	g	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B		14,895	14,895	14,895	14,895	14,895	14,895	14,895	14,895	14,895	14,895	14,895	14,895	14,895	
3	Less: Accumulated Depreciation (C		(5,627)	(5,685)	(5,743)	(5,802)	(5,860)	(5,918)	(5,977)	(6,035)	(6,093)	(6,152)	(6,210)	(6,268)	(6,327)	
4	CWIP - Non Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A		9,268	9,210	9,151	9,093	9,035	8,976	8,918	8,860	8,801	8,743	8,685	8,626	8,568	
6	Average Net Investment			9,239	9,181	9,122	9,064	9,006	8,947	8,889	8,830	8,772	8,714	8,655	8,597	
7	Return on Average Net Investment															
	a	Equity Component (D)		46	45	45	45	45	44	44	44	43	43	43	43	530
	b	Debt Component		7	7	7	7	7	7	6	6	6	6	6	6	78
8	Investment Expenses															
	a	Depreciation (E)		58	58	58	58	58	58	58	58	58	58	58	58	700
	b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H			111	111	110	110	110	109	109	109	108	108	108	107	1,308

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicabl
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Remova
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this prograr
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8E

JANUARY 2021 THROUGH DECEMBER 2021
421-Crist Common FTIR Monitor - Base

		Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments															
	a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b	Clearings to Plan		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
	f	Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
	g	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B		0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C		0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A		0	0	0	0	0	0	0	0	0	0	0	0	0	
6	Average Net Investment			0	0	0	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investmen															
	a	Equity Component (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b	Debt Component		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a	Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H			0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicabl
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Remova
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this prograr
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8E

JANUARY 2021 THROUGH DECEMBER 2021
422-Precipitator Upgrades for CAM Compliance - Base

	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
f	Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
g	Other (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C	7,632,753	7,632,753	7,632,753	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Capital Recovery Unamortized Balance	0	0	0	7,632,753	7,632,753	7,632,753	7,632,753	7,632,753	7,632,753	7,632,753	7,632,753	7,632,753	7,632,753	
6	Net Investment (Lines 2+3+4+5) (A	7,632,753	7,632,753	7,632,753	7,632,753	7,632,753	7,632,753	7,632,753	7,632,753	7,632,753	7,632,753	7,632,753	7,632,753	7,632,753	
7	Average Net Investment		7,632,753	7,632,753	7,632,753	7,632,753	7,632,753	7,632,753	7,632,753	7,632,753	7,632,753	7,632,753	7,632,753	7,632,753	
8	Return on Average Net Investment														
a	Equity Component (D)		37,790	37,790	37,790	37,790	37,790	37,790	37,790	37,790	37,790	37,790	37,790	37,790	453,477
b	Debt Component		5,580	5,580	5,580	5,580	5,580	5,580	5,580	5,580	5,580	5,580	5,580	5,580	66,955
9	Investment Expenses														
a	Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Total System Recoverable Expenses (H		43,369	43,369	43,369	43,369	43,369	43,369	43,369	43,369	43,369	43,369	43,369	43,369	520,432

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicabl
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Remova
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this prograr
(H) Line 8 + 9
(I) Regulatory assets approved by Order No. PSC-2021-0115-PAA-EI, issued March 22, 202

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8E

JANUARY 2021 THROUGH DECEMBER 2021
424-Crist Water Conservation - Base

		Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments															
	a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
	f	Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
	g	Other (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)		15,156,528	15,156,528	15,156,528	15,156,528	15,156,528	15,156,528	15,156,528	15,156,528	15,156,528	15,156,528	15,156,528	15,156,528	15,156,528	
3	Less: Accumulated Depreciation (C)		(2,043,873)	(2,094,394)	(2,144,916)	(5,540,121)	(5,590,643)	(5,641,165)	(5,691,686)	(5,742,208)	(5,792,730)	(5,843,252)	(5,893,773)	(5,944,295)	(5,994,817)	
4	CWIP - Non Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Capital Recovery Unamortized Balance		0	0	0	3,344,683	3,344,683	3,344,683	3,344,683	3,344,683	3,344,683	3,344,683	3,344,683	3,344,683	3,344,683	
6	Net Investment (Lines 2+3+4+5) (A)		13,112,656	13,062,134	13,011,612	12,961,091	12,910,569	12,860,047	12,809,525	12,759,003	12,708,482	12,657,960	12,607,438	12,556,916	12,506,395	
7	Average Net Investment			13,087,395	13,036,873	12,986,351	12,935,830	12,885,308	12,834,786	12,784,264	12,733,743	12,683,221	12,632,699	12,582,177	12,531,655	
8	Return on Average Net Investment															
	a	Equity Component (D)		64,796	64,546	64,295	64,045	63,795	63,545	63,295	63,045	62,795	62,544	62,294	62,044	761,040
	b	Debt Component		9,567	9,530	9,493	9,456	9,419	9,382	9,345	9,308	9,271	9,235	9,198	9,161	112,365
9	Investment Expenses															
	a	Depreciation (E)		50,522	50,522	50,522	50,522	50,522	50,522	50,522	50,522	50,522	50,522	50,522	50,522	606,261
	b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Total System Recoverable Expenses (H)			124,884	124,597	124,310	124,023	123,736	123,449	123,162	122,875	122,588	122,301	122,014	121,727	1,479,666

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this program
(H) Line 8 + 9
(I) Regulatory assets approved by Order No. PSC-2021-0115-PAA-EI, issued March 22, 2021

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8E

JANUARY 2021 THROUGH DECEMBER 2021
425-Plant NPDES Permit Compliance Projects - Base

		Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments															
	a	Expenditures/Additions		24,528	1,909	0	0	0	0	0	0	0	0	0	0	26,437
	b	Clearings to Plant		0	0	0	0	0	77,326	0	0	0	0	0	0	77,326
	c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
	f	Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
	g	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)		9,947,072	9,947,072	9,947,072	9,947,072	9,947,072	9,947,072	10,024,398	10,024,398	10,024,398	10,024,398	10,024,398	10,024,398	10,024,398	
3	Less: Accumulated Depreciation (C)		(3,075,888)	(3,109,045)	(3,142,202)	(3,175,359)	(3,208,516)	(3,241,672)	(3,274,958)	(3,308,373)	(3,341,788)	(3,375,203)	(3,408,618)	(3,442,033)	(3,475,448)	
4	CWIP - Non Interest Bearing		50,890	75,418	77,326	77,326	77,326	77,326	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)		6,922,073	6,913,444	6,882,196	6,849,039	6,815,882	6,782,725	6,749,440	6,716,025	6,682,610	6,649,195	6,615,780	6,582,365	6,548,950	
6	Average Net Investment			6,917,759	6,897,820	6,865,618	6,832,461	6,799,304	6,766,082	6,732,732	6,699,317	6,665,902	6,632,487	6,599,072	6,565,658	
7	Return on Average Net Investment															
	a	Equity Component (D)		34,250	34,151	33,992	33,828	33,663	33,499	33,334	33,168	33,003	32,837	32,672	32,507	400,903
	b	Debt Component		5,057	5,042	5,019	4,995	4,970	4,946	4,922	4,897	4,873	4,848	4,824	4,799	59,192
8	Investment Expenses															
	a	Depreciation (E)		33,157	33,157	33,157	33,157	33,157	33,286	33,415	33,415	33,415	33,415	33,415	33,415	399,560
	b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)			72,464	72,350	72,167	71,979	71,791	71,731	71,670	71,480	71,291	71,101	70,911	70,721	859,655

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this program
(H) Line 7 + 8

FORM: 42-8E

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2021 THROUGH DECEMBER 2021
425-Plant NPDES Permit Compliance Projects - Intermediate

		Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments															
	a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
	f	Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
	g	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B		3,798,266	3,798,266	3,798,266	3,798,266	3,798,266	3,798,266	3,798,266	3,798,266	3,798,266	3,798,266	3,798,266	3,798,266	3,798,266	
3	Less: Accumulated Depreciation (C		(402,516)	(417,392)	(432,269)	(447,145)	(462,022)	(476,898)	(491,775)	(506,651)	(521,528)	(536,404)	(551,281)	(566,158)	(581,034)	
4	CWIP - Non Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A		3,395,751	3,380,874	3,365,998	3,351,121	3,336,244	3,321,368	3,306,491	3,291,615	3,276,738	3,261,862	3,246,985	3,232,109	3,217,232	
6	Average Net Investment			3,388,312	3,373,436	3,358,559	3,343,683	3,328,806	3,313,930	3,299,053	3,284,177	3,269,300	3,254,424	3,239,547	3,224,670	
7	Return on Average Net Investmen															
	a	Equity Component (D)		16,776	16,702	16,628	16,555	16,481	16,407	16,334	16,260	16,186	16,113	16,039	15,965	196,445
	b	Debt Component		2,477	2,466	2,455	2,444	2,433	2,422	2,412	2,401	2,390	2,379	2,368	2,357	29,005
8	Investment Expenses															
	a	Depreciation (E)		14,877	14,877	14,877	14,877	14,877	14,877	14,877	14,877	14,877	14,877	14,877	14,877	178,518
	b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H			34,129	34,044	33,960	33,875	33,791	33,706	33,622	33,537	33,453	33,368	33,284	33,199	403,968

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicabl
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Remova
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this prograr
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2021 THROUGH DECEMBER 2021
426-Air Quality Compliance Program - Base

Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1 Investments														
a Expenditures/Additions		181,575	180,895	(267,286)	323,694	(914,973)	666,244	806,121	1,100,217	617,976	378,058	261,789	1,230,563	4,564,872
b Clearings to Plant		9	1,465	406,456	(30,207)	236,189	320,747	353,539	200,738	1,658,070	4,517,007	168,672	2,796,760	10,629,444
c Retirements		0	0	(119,621)	(74,948)	(787,061)	0	0	0	0	0	0	0	(981,630)
d Cost of Removal		(15,881)	227	4,649	6,162	21,097	0	0	0	0	0	0	0	16,254
e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
f Transfer Adjustments		0	0	0	361	0	0	0	0	0	0	0	0	361
g Other (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
2 Plant-in-Service/Depreciation Base (B	863,867,940	863,867,948	863,869,413	864,275,869	864,245,662	864,481,851	864,802,598	865,156,137	865,356,875	867,014,945	871,531,952	871,700,623	874,497,384	
3 Less: Accumulated Depreciation (C	119,785,376	117,457,266	115,145,254	(197,464,290)	(199,696,809)	(201,202,279)	(203,514,970)	(205,828,526)	(208,142,747)	(210,459,818)	(212,786,871)	(215,121,422)	(217,459,960)	
4 CWIP - Non Interest Bearing	5,492,970	5,674,545	5,855,440	5,588,153	5,911,847	4,996,875	5,663,119	6,469,240	7,569,457	8,187,432	8,565,490	8,827,279	10,057,842	
5 Capital Recovery Unamortized Balance	0	0	0	310,421,059	310,421,059	310,421,059	310,421,059	310,421,059	310,421,059	310,421,059	310,421,059	310,421,059	310,421,059	
6 Net Investment (Lines 2+3+4+5) (A	989,146,286	986,999,759	984,870,107	982,820,792	980,881,759	978,697,505	977,371,806	976,217,909	975,204,643	975,163,618	977,731,630	975,827,539	977,516,325	
7 Average Net Investment		988,073,023	985,934,933	983,845,449	981,851,275	979,789,632	978,034,656	976,794,857	975,711,276	975,184,131	976,447,624	976,779,585	976,671,932	
8 Return on Average Net Investment														
a Equity Component (D)		4,891,950	4,881,364	4,871,019	4,861,146	4,850,938	4,842,250	4,836,111	4,830,747	4,828,137	4,834,392	4,836,036	4,835,503	58,199,591
b Debt Component		722,281	720,718	719,191	717,733	716,226	714,943	714,037	713,245	712,860	713,783	714,026	713,947	8,592,992
9 Investment Expenses														
a Depreciation (E)		2,312,230	2,312,239	2,312,753	2,313,269	2,313,628	2,312,691	2,313,557	2,314,221	2,317,071	2,327,053	2,334,552	2,338,538	27,821,800
b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d Property Taxes		539,205	541,720	540,462	540,462	540,462	540,462	540,462	540,462	540,462	540,462	540,462	540,462	6,485,548
e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
10 Total System Recoverable Expenses (H		8,465,666	8,456,041	8,443,426	8,432,611	8,421,255	8,410,346	8,404,167	8,398,675	8,398,529	8,415,690	8,425,076	8,428,450	101,099,931

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicabl
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Remova
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this prograr
(H) Line 8 + 9
(I) Regulatory assets approved by Order No. PSC-2021-0115-PAA-EI, issued March 22, 202

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2021 THROUGH DECEMBER 2021
426-Air Quality Compliance Program - Genera

		Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments															
	a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b	Clearings to Plan		0	0	0	7,005	0	0	0	0	0	0	0	0	7,005
	c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
	f	Transfer Adjustments		0	0	0	1,566	0	0	0	0	0	0	0	0	1,566
	g	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B		0	0	0	0	7,005	7,005	7,005	7,005	7,005	7,005	7,005	7,005	7,005	
3	Less: Accumulated Depreciation (C		0	0	0	0	(1,597)	(1,627)	(1,657)	(1,688)	(1,718)	(1,748)	(1,779)	(1,809)	(1,839)	
4	CWIP - Non Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A		0	0	0	0	5,408	5,378	5,348	5,317	5,287	5,257	5,226	5,196	5,166	
6	Average Net Investment			0	0	0	2,704	5,393	5,363	5,333	5,302	5,272	5,242	5,211	5,181	
7	Return on Average Net Investmen															
	a	Equity Component (D)		0	0	0	13	27	27	26	26	26	26	26	26	223
	b	Debt Component		0	0	0	2	4	4	4	4	4	4	4	4	33
8	Investment Expenses															
	a	Depreciation (E)		0	0	0	30	30	30	30	30	30	30	30	30	273
	b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H			0	0	0	46	61	61	61	60	60	60	60	60	529

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicabl
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Remova
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this prograr
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8E

JANUARY 2021 THROUGH DECEMBER 2021
426-Air Quality Compliance Program - Peaking

		Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments															
	a	Expenditures/Additions		0	0	0	(43,516)	9,557	0	0	0	0	0	0	0	(33,959)
	b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
	f	Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
	g	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B		229,742	229,742	229,742	229,742	229,742	229,742	229,742	229,742	229,742	229,742	229,742	229,742	229,742	
3	Less: Accumulated Depreciation (C		(111,643)	(112,849)	(114,055)	(115,261)	(116,467)	(117,673)	(118,880)	(120,086)	(121,292)	(122,498)	(123,704)	(124,910)	(126,116)	
4	CWIP - Non Interest Bearing		78,196	78,196	78,196	78,196	34,679	44,237	44,237	44,237	44,237	44,237	44,237	44,237	44,237	
5	Net Investment (Lines 2+3+4) (A		196,294	195,088	193,882	192,676	147,954	156,305	155,099	153,892	152,686	151,480	150,274	149,068	147,862	
6	Average Net Investment			195,691	194,485	193,279	170,315	152,129	155,702	154,496	153,289	152,083	150,877	149,671	148,465	
7	Return on Average Net Investmen															
	a	Equity Component (D)		969	963	957	843	753	771	765	759	753	747	741	735	9,756
	b	Debt Component		143	142	141	125	111	114	113	112	111	110	109	109	1,440
8	Investment Expenses															
	a	Depreciation (E)		1,206	1,206	1,206	1,206	1,206	1,206	1,206	1,206	1,206	1,206	1,206	1,206	14,474
	b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H			2,318	2,311	2,304	2,174	2,071	2,091	2,084	2,077	2,070	2,063	2,057	2,050	25,670

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicabl
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Remova
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this progra
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8E

JANUARY 2021 THROUGH DECEMBER 2021
426-Air Quality Compliance Program - Transmissio

	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
a	Expenditures/Addition		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Clearings to Plan		(7,005)	0	0	0	0	0	0	0	0	0	0	0	(7,005)
c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
f	Transfer Adjustments		(1,958)	0	0	0	0	0	0	0	0	0	0	0	(1,958)
g	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B	6,079,391	6,072,386	6,072,386	6,072,386	6,072,386	6,072,386	6,072,386	6,072,386	6,072,386	6,072,386	6,072,386	6,072,386	6,072,386	
3	Less: Accumulated Depreciation (C	(1,728,284)	(1,740,582)	(1,754,839)	(1,769,095)	(1,783,373)	(1,797,634)	(1,811,895)	(1,826,156)	(1,840,417)	(1,854,678)	(1,868,939)	(1,883,200)	(1,897,461)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A	4,351,107	4,331,804	4,317,547	4,303,291	4,289,013	4,274,752	4,260,491	4,246,230	4,231,969	4,217,708	4,203,447	4,189,186	4,174,925	
6	Average Net Investmen		4,341,455	4,324,675	4,310,419	4,296,152	4,281,882	4,267,621	4,253,360	4,239,099	4,224,838	4,210,577	4,196,316	4,182,055	
7	Return on Average Net Investmen														
a	Equity Component (D)		21,495	21,411	21,341	21,270	21,200	21,129	21,058	20,988	20,917	20,847	20,776	20,705	253,137
b	Debt Component		3,174	3,161	3,151	3,140	3,130	3,120	3,109	3,099	3,088	3,078	3,068	3,057	37,375
8	Investment Expenses														
a	Depreciation (E)		14,256	14,256	14,256	14,278	14,261	14,261	14,261	14,261	14,261	14,261	14,261	14,261	171,135
b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H		38,925	38,829	38,748	38,689	38,591	38,510	38,429	38,348	38,267	38,185	38,104	38,023	461,647

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicabl
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Remova
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this progra
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2021 THROUGH DECEMBER 2021
427-General Water Quality - Base

Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1 Investments														
a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
f Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
g Other (G)		73,872	1,063,469	2,118,074	94,489	58,074	147,808	387,108	387,120	1,199,192	1,199,166	1,199,146	1,927,865	9,855,385
2 Plant-in-Service/Depreciation Base (B	996,766	996,766	996,766	996,766	996,766	996,766	996,766	996,766	996,766	996,766	996,766	996,766	996,766	
3 Less: Accumulated Depreciation (C	(89,664)	(92,987)	(96,309)	(99,632)	(102,954)	(106,277)	(109,599)	(112,922)	(116,244)	(119,567)	(122,890)	(126,212)	(129,535)	
4 CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Capital Recovery Unamortized Balance	4,049,961	4,123,833	5,157,430	7,254,341	7,312,489	7,337,638	7,452,310	7,805,391	8,157,194	9,318,424	10,475,631	11,628,821	13,505,519	
6 Net Investment (Lines 2 + 3 + 4) (A	4,957,063	5,027,612	6,057,886	8,151,475	8,206,300	8,228,128	8,339,477	8,689,235	9,037,715	10,195,623	11,349,508	12,499,375	14,372,750	
7 Average Net Investment		4,992,338	5,542,749	7,104,681	8,178,888	8,217,214	8,283,802	8,514,356	8,863,475	9,616,669	10,772,565	11,924,441	13,436,062	
8 Return on Average Net Investment														
a Equity Component (D)		24,717	27,442	35,175	40,494	40,683	41,013	42,155	43,883	47,612	53,335	59,038	66,522	522,069
b Debt Component		3,649	4,052	5,194	5,979	6,007	6,055	6,224	6,479	7,030	7,875	8,717	9,822	77,082
9 Investment Expenses														
a Depreciation (E)		3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	39,871
b Amortization (F)		0	29,872	21,163	36,341	32,924	33,136	34,027	35,318	37,962	41,959	45,956	51,168	399,827
c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e Other		0	0	0	0	0	0	0	0	0	0	0	0	0
10 Total System Recoverable Expenses (H		31,689	64,689	64,855	86,136	82,937	83,527	85,729	89,003	95,926	106,491	117,033	130,834	1,038,849

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicabl
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Remova
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Associated to Regulatory Asse
(H) Line 8 + 9

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8E

JANUARY 2021 THROUGH DECEMBER 2021
428-Coal Combustion Residuals - Base

		Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments															
	a	Expenditures/Additions		141,187	330,789	(9,464,331)	168,971	167,673	1,203,024	2,079,631	1,651,705	1,919,231	1,770,044	1,886,499	5,849,082	7,703,507
	b	Clearings to Plant		(188,141)	61,856	22,072	10,140,987	(30,794)	0	0	0	0	0	0	9,508,282	19,514,262
	c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Cost of Removal		(184,811)	(871,640)	(891,538)	(674,687)	(800,558)	0	0	0	0	0	0	0	(3,423,234)
	e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
	f	Transfer Adjustments		0	0	0	35,714	0	0	0	0	0	0	0	0	35,714
	g	Other (G)		853,085	504,686	784,613	669,035	898,391	1,193,769	1,269,456	565,632	558,779	847,610	1,145,061	1,662,358	10,952,476
2	Plant-in-Service/Depreciation Base (B)		34,431,275	34,243,134	34,304,990	34,327,062	44,468,049	44,437,255	44,437,255	44,437,255	44,437,255	44,437,255	44,437,255	44,437,255	53,945,536	
3	Less: Accumulated Depreciation (C)		(34,523,627)	(34,401,433)	(33,702,016)	(32,927,917)	(32,431,365)	(31,773,526)	(31,916,202)	(32,058,878)	(32,201,554)	(32,344,230)	(32,486,906)	(32,629,582)	(32,784,096)	
4	CWIP - Non Interest Bearing		25,393,827	25,535,014	25,865,803	16,401,473	16,570,444	16,738,117	17,941,142	20,020,773	21,672,477	23,591,708	25,361,752	27,248,251	33,097,334	
5	Capital Recovery Unamortized Balance		25,593,314	26,446,399	26,861,975	27,600,429	28,222,094	29,071,810	30,215,159	31,432,143	31,943,773	32,447,614	33,239,114	34,326,404	35,928,652	
6	Net Investment (Lines 2 + 3 + 4 + 5) (A)		50,894,789	51,823,113	53,330,752	45,401,047	56,829,222	58,473,655	60,677,353	63,831,292	65,851,951	68,132,347	70,551,214	73,382,328	90,187,426	
7	Average Net Investment			51,358,951	52,576,932	49,365,899	51,115,134	57,651,438	59,575,504	62,254,323	64,841,622	66,992,149	69,341,781	71,966,771	81,784,877	
8	Return on Average Net Investment															
	a	Equity Component (D)		254,278	260,308	244,411	253,071	285,432	294,958	308,221	321,031	331,678	343,311	356,307	404,917	3,657,924
	b	Debt Component		37,543	38,434	36,086	37,365	42,143	43,550	45,508	47,399	48,971	50,689	52,608	59,785	540,081
9	Investment Expenses															
	a	Depreciation (E)		62,617	172,223	117,439	142,421	142,719	142,676	142,676	142,676	142,676	142,676	142,676	154,514	1,647,990
	b	Amortization (F)		0	89,110	46,159	47,370	48,676	50,420	52,472	54,001	54,938	56,110	57,771	60,111	617,138
	c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Property Taxes		6,059	6,088	6,073	6,073	6,073	6,073	6,073	6,073	6,073	6,073	6,073	6,073	72,879
	e	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Total System Recoverable Expenses (H)			360,498	566,163	450,168	486,300	525,044	537,677	554,951	571,181	584,337	598,860	615,435	685,399	6,536,013

Notes:
(A) "Other" Includes Cost of Removal for Daniel 1&2 and Scherer Ash Pond
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Remova
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Associated to Regulatory Asse
(H) Line 8 + 9

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8E

JANUARY 2021 THROUGH DECEMBER 2021
428-Coal Combustion Residuals - Intermediat

	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
a	Expenditures/Additions		2,730,982	1,454,535	2,234,937	1,577,138	640,852	376,985	201,814	203,212	291,718	199,445	477,213	290,951	10,679,781
b	Clearings to Plan		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
f	Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
g	Other (G)		174,771	562,510	108,718	534,643	654,793	771,511	1,354,001	1,318,125	1,965,554	1,046,014	912,246	802,544	10,205,429
2	Plant-in-Service/Depreciation Base (B	2,634,177	2,634,177	2,634,177	2,634,177	2,634,177	2,634,177	2,634,177	2,634,177	2,634,177	2,634,177	2,634,177	2,634,177	2,634,177	
3	Less: Accumulated Depreciation (C	(146,916)	(157,233)	(167,550)	(177,867)	(188,184)	(198,502)	(208,819)	(219,136)	(229,453)	(239,770)	(250,088)	(260,405)	(270,722)	
4	CWIP - Non Interest Bearing	76,172,999	78,903,981	80,358,515	82,593,452	84,170,590	84,811,442	85,188,427	85,390,241	85,593,453	85,885,171	86,084,617	86,561,830	86,852,780	
5	Capital Recovery Unamortized Balance	8,335,180	8,509,951	9,043,482	9,136,855	9,655,617	10,293,538	11,046,989	12,381,158	13,677,225	15,617,983	15,590,679	15,561,742	15,531,377	
6	Net Investment (Lines 2 + 3 + 4) (A	86,995,440	89,890,876	91,868,624	94,186,617	96,272,200	97,540,655	98,660,774	100,186,440	101,675,401	103,897,561	104,059,384	104,497,344	104,747,612	
7	Average Net Investment		88,443,158	90,879,750	93,027,620	95,229,408	96,906,427	98,100,715	99,423,607	100,930,920	102,786,481	103,978,473	104,278,364	104,622,478	
8	Return on Average Net Investmen														
a	Equity Component (D)		437,882	449,946	460,580	471,481	479,784	485,697	492,246	499,709	508,896	514,797	516,282	517,986	5,835,285
b	Debt Component		64,652	66,433	68,003	69,613	70,839	71,712	72,679	73,781	75,137	76,008	76,227	76,479	861,562
9	Investment Expenses														
a	Depreciation (E)		10,317	10,317	10,317	10,317	10,317	10,317	10,317	10,317	10,317	10,317	10,317	10,317	123,806
b	Amortization (F)		0	28,980	15,345	15,881	16,872	18,060	19,832	22,059	24,795	27,305	28,936	30,365	248,429
c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Total System Recoverable Expenses (H		512,851	555,676	554,245	567,291	577,811	585,786	595,074	605,865	619,145	628,427	631,763	635,148	7,069,082

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicabl
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Remova
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Associated to Regulatory Asse
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2021 THROUGH DECEMBER 2021
429-Steam Electric Effluent Limitations Guidelines - Base

		Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments															
	a	Expenditures/Additions		142,984	1,384	1,708	9,427	(415,350)	17,917	428,435	17,917	21,581	(10,023)	(10,023)	9,043	215,000
	b	Clearings to Plant		0	437	5	3	(3)	0	0	0	0	0	0	0	442
	c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
	f	Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
	g	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B		6,042,591	6,042,591	6,043,028	6,043,033	6,043,036	6,043,033	6,043,033	6,043,033	6,043,033	6,043,033	6,043,033	6,043,033	6,043,033	
3	Less: Accumulated Depreciation (C		(650,031)	(669,596)	(689,162)	(708,727)	(728,293)	(747,859)	(767,425)	(786,990)	(806,556)	(826,122)	(845,687)	(865,253)	(884,819)	
4	CWIP - Non Interest Bearing		913,989	1,056,973	1,058,357	1,060,065	1,069,492	654,142	672,059	1,100,494	1,118,411	1,139,991	1,129,969	1,119,946	1,128,989	
5	Net Investment (Lines 2 + 3 + 4) (A		6,306,548	6,429,967	6,412,223	6,394,371	6,384,235	5,949,316	5,947,667	6,356,536	6,354,887	6,356,902	6,327,314	6,297,725	6,287,203	
6	Average Net Investment			6,368,258	6,421,095	6,403,297	6,389,303	6,166,776	5,948,492	6,152,102	6,355,712	6,355,895	6,342,108	6,312,520	6,292,464	
7	Return on Average Net Investment															
	a	Equity Component (D)		31,529	31,791	31,703	31,633	30,532	29,451	30,459	31,467	31,468	31,400	31,253	31,154	373,840
	b	Debt Component		4,655	4,694	4,681	4,671	4,508	4,348	4,497	4,646	4,646	4,636	4,614	4,600	55,196
8	Investment Expenses															
	a	Depreciation (E)		19,565	19,565	19,566	19,566	19,566	19,566	19,566	19,566	19,566	19,566	19,566	19,566	234,788
	b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Property Taxes		197	198	197	197	197	197	197	197	197	197	197	197	2,367
	e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H			55,946	56,248	56,146	56,067	54,802	53,562	54,719	55,876	55,877	55,799	55,631	55,517	666,191

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Remova
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this prograr
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-8E

JANUARY 2021 THROUGH DECEMBER 2021
430-316b Cooling Water Intake Structure Regulation - Intermediate

		Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments															
	a	Expenditures/Additions		(199,008)	(27,429)	12,627	(3,905,036)	0	0	0	0	0	0	0	0	(4,118,847)
	b	Clearings to Plant		0	0	0	3,906,456	553	0	0	0	0	0	0	0	3,907,009
	c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
	f	Transfer Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
	g	Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B		0	0	0	0	3,906,456	3,907,009	3,907,009	3,907,009	3,907,009	3,907,009	3,907,009	3,907,009	3,907,009	
3	Less: Accumulated Depreciation (C		87,586	87,586	87,586	87,586	79,936	64,634	49,332	34,030	18,728	3,426	(11,876)	(27,178)	(42,480)	
4	CWIP - Non Interest Bearing		4,118,847	3,919,839	3,892,409	3,905,036	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A		4,206,432	4,007,425	3,979,995	3,992,622	3,986,391	3,971,643	3,956,341	3,941,039	3,925,737	3,910,435	3,895,133	3,879,831	3,864,529	
6	Average Net Investment			4,106,928	3,993,710	3,986,309	3,989,507	3,979,017	3,963,992	3,948,690	3,933,388	3,918,086	3,902,784	3,887,482	3,872,180	
7	Return on Average Net Investment															
	a	Equity Component (D)		20,333	19,773	19,736	19,752	19,700	19,626	19,550	19,474	19,398	19,323	19,247	19,171	235,084
	b	Debt Component		3,002	2,919	2,914	2,916	2,909	2,898	2,886	2,875	2,864	2,853	2,842	2,831	34,709
8	Investment Expenses															
	a	Depreciation (E)		0	0	0	7,650	15,301	15,302	15,302	15,302	15,302	15,302	15,302	15,302	130,066
	b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H			23,336	22,692	22,650	30,319	37,910	37,825	37,738	37,652	37,565	37,478	37,391	37,304	399,859

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicabl
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Remova
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this prograr
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS,DEPRECIATION, AND TAXES

FORM: 42-8E

JANUARY 2021 THROUGH DECEMBER 2021
Regulatory Asset Smith Units 1 & 2 - Intermediate

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Regulatory Asset Balance 182.2 (B	17,193,984	17,075,405	16,956,826	16,838,246	16,719,667	16,601,088	16,482,509	16,482,509	16,482,509	16,482,509	16,482,509	16,482,509	16,482,509	
2	Less Amortization (C)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	
3	Net Regulatory Asset Balance (Lines 1 + 2) (A	17,075,405	16,956,826	16,838,247	16,719,667	16,601,088	16,482,509	16,363,930	16,363,930	16,363,930	16,363,930	16,363,930	16,363,930	16,363,930	
4	Average Regulatory Asset Balance		17,016,115	16,897,536	16,778,957	16,660,377	16,541,798	16,423,219	16,363,930	16,363,930	16,363,930	16,363,930	16,363,930	16,363,930	
5	Return on Average Regulatory Asset Balance														
a	Equity Component (Line 6 x Equity Component x 1/12) (D		84,247	83,660	83,073	82,486	81,898	81,311	81,018	81,018	81,018	81,018	81,018	81,018	982,781
b	Debt Component (Line 6 x Debt Component x 1/12		12,439	12,352	12,265	12,179	12,092	12,005	11,962	11,962	11,962	11,962	11,962	11,962	145,105
6	Amortization Expense														
a	Recoverable Costs Allocated to Energy		118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	1,422,950
b	Other (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
7	Total Jurisdictional Recoverable Costs (Lines 5 + 6		215,265	214,591	213,917	213,243	212,570	211,896	211,559	211,559	211,559	211,559	211,559	211,559	2,550,836

Notes:
(A) End of period Regulatory Asset Balance
(B) Beginning of period Regulatory Asset Balance
(C) Regulatory Asset has a 15 year amortization period
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%
(E) Regulatory Asset has a 15 year amortization period
(F) Description and reason for "Other" adjustments to regulatory asse

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS,DEPRECIATION, AND TAXES

FORM: 42-8E

JANUARY 2021 THROUGH DECEMBER 2021
For Program: Emission Allowances

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
a	Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
b	Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
c	Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
a	FERC 158.1 Allowance Inventory	6,291,628	6,291,628	6,291,628	6,291,628	6,292,104	6,290,695	6,290,691	6,290,686	6,290,681	6,290,677	6,290,675	6,290,673	6,290,671	
b	FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
c	FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
d	FERC 254 Regulatory Liabilities - Gains	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Total Working Capital Balance	6,291,628	6,291,628	6,291,628	6,291,628	6,292,104	6,290,695	6,290,691	6,290,686	6,290,681	6,290,677	6,290,675	6,290,673	6,290,671	
4	Average Net Working Capital Balance		6,291,628	6,291,628	6,291,628	6,291,866	6,291,400	6,290,693	6,290,689	6,290,684	6,290,679	6,290,676	6,290,674	6,290,672	
5	Return on Average Net Working Capital Balance														
a	Equity Component (Line 4 x Equity Component x 1/12) (A)		31,150	31,150	31,150	31,151	31,149	31,145	31,145	31,145	31,145	31,145	31,145	31,145	373,765
b	Debt Component (Line 4 x Debt Component x 1/12		4,599	4,599	4,599	4,599	4,599	4,598	4,598	4,598	4,598	4,598	4,598	4,598	55,185
6	Total Return Component (B)		35,749	35,749	35,749	35,750	35,748	35,744	35,744	35,744	35,744	35,744	35,744	35,744	428,951
7	Expenses														
a	Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Allowance Expense		0	0	0	143,603	8,994	4	5	5	4	2	2	2	152,622
8	Net Expenses (C)		0	0	0	143,603	8,994	4	5	5	4	2	2	2	152,622
9	Total System Recoverable Expenses (Lines 6 + 8		35,749	35,749	35,749	179,354	44,742	35,748	35,749	35,749	35,748	35,746	35,746	35,746	581,572

Notes:
(A) The approved ROE is 10.25%.
(B) Line 6 is reported on Schedule 7E
(C) Line 8 is reported on Schedule 5E

Gulf **Schedule 8E**
Environmental Cost Recovery Clause
2021 Annual Capital Depreciation Schedule

Project	Function	Major Location	Plant	Depreciation Rate	Type	Dec-21
401-Air Quality Assurance Testing	01 - Intangible Plant	G:Intangible Plant	31670	14.29%	Amortization	-
401-Air Quality Assurance Testing	02 - Steam Generation Plant	G:Crist Plant	31670	14.29%	Amortization	83,954
401-Air Quality Assurance Testing Total						**83,954**
402-Crist 5, 6 & 7 Precipitator Projects	02 - Steam Generation Plant	CRIST PLANT - Common A	31400	4.00%	Depreciation	291,139
402-Crist 5, 6 & 7 Precipitator Projects	02 - Steam Generation Plant	CRIST PLANT - Unit 5	31200	4.00%	Depreciation	453,061
402-Crist 5, 6 & 7 Precipitator Projects	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31200	4.00%	Depreciation	7,646,441
402-Crist 5, 6 & 7 Precipitator Projects	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31200	4.00%	Depreciation	147,682
402-Crist 5, 6 & 7 Precipitator Projects Total						**8,538,323**
403-Crist 7 Flue Gas Conditioning	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31200	4.00%	Depreciation	-
403-Crist 7 Flue Gas Conditioning Total						**-**
404-Low NOx Burners, Crist 6 & 7	02 - Steam Generation Plant	CRIST PLANT - Common A	31200	4.00%	Depreciation	131,183
404-Low NOx Burners, Crist 6 & 7	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31200	4.00%	Depreciation	2,902,903
404-Low NOx Burners, Crist 6 & 7	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31400	4.00%	Depreciation	11,338
404-Low NOx Burners, Crist 6 & 7	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31200	4.00%	Depreciation	5,516,349
404-Low NOx Burners, Crist 6 & 7	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31500	4.00%	Depreciation	44,385
404-Low NOx Burners, Crist 6 & 7	02 - Steam Generation Plant	G:Crist Plant	31670	14.29%	Amortization	143,759
404-Low NOx Burners, Crist 6 & 7 Total						**8,749,918**
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	Depreciation	200,489
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	CRIST PLANT - Common A	31200	4.00%	Depreciation	3,282,349
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	CRIST PLANT - Unit 4	31200	4.00%	Depreciation	24,046
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	CRIST PLANT - Unit 5	31200	4.00%	Depreciation	20,502
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31200	4.00%	Depreciation	217,721
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31200	4.00%	Depreciation	341,530
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	DANIEL P-Com 1-2	31200	3.00%	Depreciation	356,393
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	DANIEL P-Com 1-2	31500	3.00%	Depreciation	196,553
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	DANIEL P-Com 1-2	31670	14.29%	Amortization	3,097
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	DANIEL PLANT - Unit 1	31200	3.00%	Depreciation	32,584
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	DANIEL PLANT - Unit 2	31200	3.00%	Depreciation	37,519
405-CEMS - Plants Crist & Daniel Total						**4,712,783**
406-Substation Contamination Remediation	06 - Transmission Plant - Electric	G:Transmission Substations	35200	1.70%	Depreciation	339,156
406-Substation Contamination Remediation	06 - Transmission Plant - Electric	G:Transmission Substations	35300	2.80%	Depreciation	489,301
406-Substation Contamination Remediation	07 - Distribution Plant - Electric	G:Distribution	36100	1.90%	Depreciation	587,654
406-Substation Contamination Remediation	07 - Distribution Plant - Electric	G:Distribution	36200	3.10%	Depreciation	3,142,969
406-Substation Contamination Remediation Total						**4,559,079**
407-Raw Water Well Flowmeters Plants Crist & Smith	02 - Steam Generation Plant	CRIST PLANT - Common A	31,100	4.00%	Depreciation	149,950
407-Raw Water Well Flowmeters Plants Crist & Smith	02 - Steam Generation Plant	CRIST PLANT - Common A	31200	4.00%	Depreciation	-
407-Raw Water Well Flowmeters Plants Crist & Smith	05 - Other Generation Plant	G:Smith Common - CT and CC	34300	4.70%	Depreciation	-
407-Raw Water Well Flowmeters Plants Crist & Smith Total						**149,950**
408-Crist Cooling Tower Cell	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31200	4.00%	Depreciation	-
408-Crist Cooling Tower Cell Total						**-**
409-Crist Dechlorination System	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	Depreciation	76,079
409-Crist Dechlorination System	02 - Steam Generation Plant	CRIST PLANT - Common A	31400	4.00%	Depreciation	304,619
409-Crist Dechlorination System Total						**380,697**
410-Crist Diesel Fuel Oil Remediation	02 - Steam Generation Plant	CRIST PLANT - Common A	31200	4.00%	Depreciation	20,968
410-Crist Diesel Fuel Oil Remediation Total						**20,968**
411-Crist Bulk Tanker Unloading Second Containment	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	Depreciation	50,748
411-Crist Bulk Tanker Unloading Second Containment	02 - Steam Generation Plant	CRIST PLANT - Common A	31200	4.00%	Depreciation	-
411-Crist Bulk Tanker Unloading Second Containment Total						**50,748**
412-Crist IWW Sampling System	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	Depreciation	59,543
412-Crist IWW Sampling System Total						**59,543**
413-Sodium Injection System	02 - Steam Generation Plant	CRIST PLANT - Common A	31200	4.00%	Depreciation	-
413-Sodium Injection System Total						**-**
414-Smith Stormwater Collection System	05 - Other Generation Plant	G:Smith Common - CT and CC	34100	4.70%	Depreciation	2,601,079
414-Smith Stormwater Collection System	05 - Other Generation Plant	G:Smith Common - CT and CC	34500	4.70%	Depreciation	163,300
414-Smith Stormwater Collection System Total						**2,764,379**
415-Smith Waste Water Treatment Facility	05 - Other Generation Plant	G:Smith Common - CT and CC	34100	4.70%	Depreciation	643,620
415-Smith Waste Water Treatment Facility Total						**643,620**
416-Daniel Ash Management Project	02 - Steam Generation Plant	DANIEL P-Com 1-2	31100	3.00%	Depreciation	7,157,673
416-Daniel Ash Management Project	02 - Steam Generation Plant	DANIEL P-Com 1-2	31200	3.00%	Depreciation	5,258,246
416-Daniel Ash Management Project	02 - Steam Generation Plant	DANIEL P-Com 1-4	31200	3.00%	Depreciation	1,633
416-Daniel Ash Management Project	02 - Steam Generation Plant	DANIEL P-Com 1-4	31670	14.29%	Amortization	639
416-Daniel Ash Management Project	02 - Steam Generation Plant	DANIEL PLANT - Unit 1	31500	3.00%	Depreciation	2,521,370
416-Daniel Ash Management Project Total						**14,939,561**
417-Smith Water Conservation	05 - Other Generation Plant	G:Smith Common - CT and CC	34100	4.70%	Depreciation	669,502
417-Smith Water Conservation	05 - Other Generation Plant	G:Smith Common - CT and CC	34500	4.70%	Depreciation	2,059,084
417-Smith Water Conservation	05 - Other Generation Plant	G:Smith Unit 3 - Combined Cycle	34100	4.70%	Depreciation	18,853,016
417-Smith Water Conservation	05 - Other Generation Plant	G:Smith Unit 3 - Combined Cycle	34500	4.70%	Depreciation	9,159
417-Smith Water Conservation Total						**21,590,761**
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	Depreciation	1,285,488
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Common A	31200	4.00%	Depreciation	804,175
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Common A	31600	4.00%	Depreciation	143,514
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Unit 4	31200	4.00%	Depreciation	1,315,960
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Unit 5	31200	4.00%	Depreciation	1,314,974
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31100	4.00%	Depreciation	2
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31200	4.00%	Depreciation	7,412,213
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31500	4.00%	Depreciation	263,775
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31200	4.00%	Depreciation	17,627,439
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31500	4.00%	Depreciation	8,173,896
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31600	4.00%	Depreciation	181,043
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	G:Crist Plant	31670	14.29%	Amortization	1,052,892
419-Crist FDEP Agreement for Ozone Attainment Total						**39,575,370**

420-SPCC Compliance	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	Depreciation	919,836
420-SPCC Compliance	05 - Other Generation Plant	G:Smith Common - CT and CC	34100	4.70%	Depreciation	14,895
420-SPCC Compliance	08 - General Plant	G:General Plant	39400	14.29%	Amortization	13,195
420-SPCC Compliance Total						**947,925**
421-Crist Common FTIR Monitor	02 - Steam Generation Plant	CRIST PLANT - Common A	31600	4.00%	Depreciation	-
421-Crist Common FTIR Monitor Total						**-**
422-Precipitator Upgrades for CAM Compliance	02 - Steam Generation Plant	CRIST PLANT - Unit 4	31200	4.00%	Depreciation	-
422-Precipitator Upgrades for CAM Compliance	02 - Steam Generation Plant	CRIST PLANT - Unit 5	31200	4.00%	Depreciation	-
422-Precipitator Upgrades for CAM Compliance Total						**-**
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	Depreciation	515,031
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Common A	31200	4.00%	Depreciation	1,474,422
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Common A	31400	4.00%	Depreciation	8,510,363
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Common A	31500	4.00%	Depreciation	2,544,385
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Common A	31600	4.00%	Depreciation	353,327
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Unit 4	31200	4.00%	Depreciation	190,220
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Unit 5	31200	4.00%	Depreciation	137,801
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31200	4.00%	Depreciation	374,984
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31400	4.00%	Depreciation	690,077
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31500	4.00%	Depreciation	39,519
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31200	4.00%	Depreciation	326,401
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31400	4.00%	Depreciation	-
424-Crist Water Conservation Total						**15,156,528**
425-Plant NPDES Permit Compliance Projects	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	Depreciation	325,432
425-Plant NPDES Permit Compliance Projects	02 - Steam Generation Plant	CRIST PLANT - Unit 4	31400	4.00%	Depreciation	1,579,996
425-Plant NPDES Permit Compliance Projects	02 - Steam Generation Plant	CRIST PLANT - Unit 5	31400	4.00%	Depreciation	1,773,231
425-Plant NPDES Permit Compliance Projects	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31200	4.00%	Depreciation	440,705
425-Plant NPDES Permit Compliance Projects	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31400	4.00%	Depreciation	5,827,708
425-Plant NPDES Permit Compliance Projects	02 - Steam Generation Plant	G:Crist Plant	31200	4.00%	Depreciation	77,326
425-Plant NPDES Permit Compliance Projects	05 - Other Generation Plant	G:Smith Common - CT and CC	34300	4.70%	Depreciation	3,798,266
425-Plant NPDES Permit Compliance Projects	05 - Other Generation Plant	G:Smith Common - CT and CC	34400	4.70%	Depreciation	-
425-Plant NPDES Permit Compliance Projects Total						**13,822,664**
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	Depreciation	74,413,061
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Common A	31200	4.00%	Depreciation	28,460,790
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Common A	31400	4.00%	Depreciation	257,354
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Common A	31500	4.00%	Depreciation	68,740,170
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Common A	31600	4.00%	Depreciation	2,902,810
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Unit 4	31200	4.00%	Depreciation	4,624,344
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Unit 4	31500	4.00%	Depreciation	2,015,231
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Unit 5	31200	4.00%	Depreciation	5,644,235
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Unit 5	31500	4.00%	Depreciation	2,293,678
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31200	4.00%	Depreciation	48,940,398
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31500	4.00%	Depreciation	25,061,479
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31200	4.00%	Depreciation	17,061,678
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31400	4.00%	Depreciation	27,860,411
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31500	4.00%	Depreciation	2,126,229
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL P-Com 1-2	31100	3.00%	Depreciation	11,334,004
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL P-Com 1-2	31200	3.00%	Depreciation	210,391,868
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL P-Com 1-2	31500	3.00%	Depreciation	16,402,310
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL P-Com 1-2	31600	3.00%	Depreciation	334,923
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL P-Com 1-2	31650	20.00%	Amortization	226,142
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL P-Com 1-2	31670	14.29%	Amortization	383,892
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL PLANT - Unit 1	31100	3.00%	Depreciation	337,967
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL PLANT - Unit 1	31200	3.00%	Depreciation	94,886,018
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL PLANT - Unit 1	31500	3.00%	Depreciation	929,672
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL PLANT - Unit 1	31600	3.00%	Depreciation	151,046
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL PLANT - Unit 2	31100	3.00%	Depreciation	-
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL PLANT - Unit 2	31200	3.00%	Depreciation	40,480,081
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL PLANT - Unit 2	31600	3.00%	Depreciation	(22,658)
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL PLANT - Unit 2	31650	20.00%	Amortization	-
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL PLANT - Unit 2	31670	14.29%	Amortization	22,658
426-Air Quality Compliance Program	02 - Steam Generation Plant	G:Crist Plant	31100	4.00%	Depreciation	4,364,736
426-Air Quality Compliance Program	02 - Steam Generation Plant	G:Crist Plant	31200	4.00%	Depreciation	371
426-Air Quality Compliance Program	02 - Steam Generation Plant	G:Crist Plant	31500	4.00%	Depreciation	93,086
426-Air Quality Compliance Program	02 - Steam Generation Plant	G:Crist Plant	31670	14.29%	Amortization	967,345
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-Common A	31100	2.20%	Depreciation	798,405
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-Common A	31200	2.20%	Depreciation	8,873,354
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-Common A	31500	2.20%	Depreciation	931,808
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-Common A	31670	14.29%	Amortization	20,761
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-Common B	31100	2.20%	Depreciation	954,286
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-Common B	31200	2.20%	Depreciation	13,355,087
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-Common B	31500	2.20%	Depreciation	126,817
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-Common B	31600	2.20%	Depreciation	557
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-Common B	31670	14.29%	Amortization	85,069
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-UNIT #3	31100	2.20%	Depreciation	5,711,882
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-UNIT #3	31200	2.20%	Depreciation	146,045,915
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-UNIT #3	31500	2.20%	Depreciation	5,888,098
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-UNIT #3	31600	2.20%	Depreciation	612
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-UNIT #3	31670	14.29%	Amortization	19,404
426-Air Quality Compliance Program	05 - Other Generation Plant	G:Smith Plant CT	34200	6.30%	Depreciation	229,742
426-Air Quality Compliance Program	06 - Transmission Plant - Electric	G:Transmission 115-500KV Lines	35400	2.00%	Depreciation	565,268
426-Air Quality Compliance Program	06 - Transmission Plant - Electric	G:Transmission 115-500KV Lines	35500	4.60%	Depreciation	515,710
426-Air Quality Compliance Program	06 - Transmission Plant - Electric	G:Transmission 115-500KV Lines	35600	2.60%	Depreciation	562,755
426-Air Quality Compliance Program	06 - Transmission Plant - Electric	G:Transmission Substations	35200	1.70%	Depreciation	229,996
426-Air Quality Compliance Program	06 - Transmission Plant - Electric	G:Transmission Substations	35300	2.80%	Depreciation	4,198,658
426-Air Quality Compliance Program	08 - General Plant	G:General Plant	39780	5.20%	Depreciation	7,005
426-Air Quality Compliance Program Total						**880,806,516**
427-General Water Quality	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	Depreciation	996,766
427-General Water Quality Total						**996,766**
428-Coal Combustion Residuals	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	Depreciation	701,657
428-Coal Combustion Residuals	02 - Steam Generation Plant	DANIEL P-Com 1-2	31100	3.00%	Depreciation	104,724
428-Coal Combustion Residuals	02 - Steam Generation Plant	DANIEL P-Com 1-2	31200	3.00%	Depreciation	27,702

428-Coal Combustion Residuals	02 - Steam Generation Plant	DANIEL PLANT - Unit 1	31200	3.00%	Depreciation	9,994,211
428-Coal Combustion Residuals	02 - Steam Generation Plant	DANIEL PLANT - Unit 2	31200	3.00%	Depreciation	9,309,468
428-Coal Combustion Residuals	02 - Steam Generation Plant	G:Crist Plant	31,100	0.00%	Dismantlement	-
428-Coal Combustion Residuals	02 - Steam Generation Plant	G:Daniel Plant	31,100	0.00%	Dismantlement	-
428-Coal Combustion Residuals	02 - Steam Generation Plant	G:Scherer Plant	31,100	0.00%	Dismantlement	
428-Coal Combustion Residuals	02 - Steam Generation Plant	G:Daniel Plant	31100	3.00%	Depreciation	-
428-Coal Combustion Residuals	02 - Steam Generation Plant	G:Scholz Plant	31100	4.70%	Depreciation	-
428-Coal Combustion Residuals	02 - Steam Generation Plant	SCHERER PLANT-Common A	31200	2.20%	Depreciation	173,114
428-Coal Combustion Residuals	02 - Steam Generation Plant	SCHERER PLANT-Common B	31000	0.00%	Land	773,371
428-Coal Combustion Residuals	02 - Steam Generation Plant	SCHERER PLANT-Common B	31100	2.20%	Depreciation	15,917,066
428-Coal Combustion Residuals	02 - Steam Generation Plant	SCHERER PLANT-Common B	31200	2.20%	Depreciation	9,954,406
428-Coal Combustion Residuals	02 - Steam Generation Plant	SCHERER PLANT-UNIT #3	31100	2.20%	Depreciation	525,049
428-Coal Combustion Residuals	02 - Steam Generation Plant	SCHERER PLANT-UNIT #3	31200	2.20%	Depreciation	6,464,769
428-Coal Combustion Residuals	05 - Other Generation Plant	G:Smith Common - CT and CC	34100	4.70%	Depreciation	1,451,586
428-Coal Combustion Residuals	05 - Other Generation Plant	G:Smith Common - CT and CC	34500	4.70%	Depreciation	1,027,022
428-Coal Combustion Residuals	05 - Other Generation Plant	G:Smith Common - CT and CC	34600	4.70%	Depreciation	155,569
428-Coal Combustion Residuals	08 - General Plant	G:General Plant	39000	2.00%	Depreciation	-
428-Coal Combustion Residuals Total						**56,579,713**
429-Steam Electric Effluent Limitations Guidelines	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	Depreciation	5,657,885
429-Steam Electric Effluent Limitations Guidelines	02 - Steam Generation Plant	SCHERER PLANT-UNIT #3	31200	2.20%	Depreciation	385,147
429-Steam Electric Effluent Limitations Guidelines Total						**6,043,033**
430-316b Cooling Water Intake Structure Regulation	05 - Other Generation Plant	G:Smith Common - CT and CC	34300	4.70%	Depreciation	3,907,009
430-316b Cooling Water Intake Structure Regulation Total						**3,907,009**
Grand Total						**1,085,079,806**

GULF POWER COMPANY
COST RECOVERY CLAUSES

Schedule 9E

Equity @ 10.25%

ACT/EST 2021 GULF WACC @10.25%
CAPITAL STRUCTURE AND COST RATES [(a)]

	ADJUSTED RETAIL	RATIO	MIDPOINT COST RATES	WEIGHTED COST	PRE-TAX WEIGHTED COST
LONG_TERM_DEBT	1,037,073,333	30.723%	2.64%	0.8101%	0.81%
SHORT_TERM_DEBT	238,450,020	7.064%	0.63%	0.0443%	0.04%
PREFERRED_STOCK	0	0.000%	0.00%	0.0000%	0.00%
CUSTOMER_DEPOSITS	22,754,205	0.674%	2.64%	0.0178%	0.02%
COMMON_EQUITY [(b)]	1,467,537,622	43.475%	10.25%	4.4562%	5.90%
DEFERRED_INCOME_TAX	594,149,179	17.601%	0.00%	0.0000%	0.00%
INVESTMENT_TAX_CREDITS					
ZERO COST	0	0.000%	0.00%	0.0000%	0.00%
WEIGHTED COST	15,645,284	0.463%	7.10%	0.0329%	0.04%
TOTAL	$3,375,609,644	100.00%		5.3613%	6.82%

CALCULATION OF THE WEIGHTED COST FOR INVESTMENT TAX CREDITS

	ADJUSTED RETAIL	RATIO	COST RATE	WEIGHTED COST	PRE TAX COST
LONG TERM DEBT	$1,037,073,333	41.41%	2.637%	1.092%	1.092%
PREFERRED STOCK	0	0.00%	0.000%	0.000%	0.000%
COMMON EQUITY	1,467,537,622	58.59%	10.250%	6.006%	7.957%
TOTAL	$2,504,610,955	100.00%		7.098%	9.049%
RATIO					

DEBT COMPONENTS:	
LONG TERM DEBT	0.8101%
SHORT TERM DEBT	0.0443%
CUSTOMER DEPOSITS	0.0178%
TAX CREDITS -WEIGHTED	0.0051%
TOTAL DEBT	**0.8773%**
EQUITY COMPONENTS:	
PREFERRED STOCK	0.0000%
COMMON EQUITY	4.4562%
TAX CREDITS -WEIGHTED	0.0278%
TOTAL EQUITY	**4.4840%**
TOTAL	5.3613%
PRE-TAX EQUITY	5.9408%
PRE-TAX TOTAL	6.8181%

Note:

(a) Forecasted capital structure includes a deferred income tax proration adjustment consistent with FPSC Order No. PSC-2020-0165-PAA-EU, Docket No. 20200118-EU.

(b) Cost rate for common equity represents Gulf's mid-point return on equity approved by the FPSC in Order No. PSC-17-0178-S-EI, Docket Nos. 160186-EI and 160170-EI.

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Commission Forms 42-1A Through 42-9A

January 2020 - December 2020
Final True-Up
Docket No. 20210007-EI

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2020 - December 2020
(in Dollars)

Line		Period Amount
1	Over/(Under) Recovery for the Period January 2020 - December 2020 (Form 42-2A, Line 5 + 6 + 10)	$ 8,328,666
2	Actual/Estimated True-Up Amount Approved for the Period January 2020 - December 2020 (Order No. PSC-2020-0433-FOF-EI)	8,097,179
3	Final True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2022 to December 2022 (Lines 1 - 2)	$ 231,488

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2020 - December 2020

End-of-Period True-Up Amount
(in Dollars)

Line	Description		Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	ECRC Revenues (net of Revenue Taxes)		$2,043,276	$2,053,327	$2,175,236	$2,506,103	$2,306,710	$2,665,667	$3,096,178	$3,018,634	$3,013,768	$2,686,622	$2,557,155	$2,373,372	30,496,048
2	True-Up Provision	18,654,948	$1,554,579	$1,554,579	$1,554,579	$1,554,579	$1,554,579	$1,554,579	$1,554,579	$1,554,579	$1,554,579	$1,554,579	$1,554,579	$1,554,579	18,654,948
	(Order No. PSC-2019-0500-FOF-EI)														
3	ECRC Revenues Applicable to Period (Lines 1 + 2)		$3,597,855	3,607,906	3,729,815	4,060,682	3,861,289	4,220,246	4,650,757	4,573,213	4,568,347	4,241,201	4,111,734	3,927,951	49,150,996
4	Jurisdictional ECRC Costs														
	a. O & M Activities (Form 42-5A, Line 9)		$1,169,339	$902,941	$1,470,579	$1,127,597	$1,473,241	$924,880	$1,665,614	$1,665,905	$1,711,042	$2,134,545	$648,052	$1,457,192	$16,350,927
	b. Capital Investment Projects (Form 42-7A, Line 9)		1,791,995	2,126,160	2,089,644	2,100,099	2,049,407	2,051,535	2,039,780	2,041,496	2,063,808	2,054,050	2,113,185	2,035,593	24,556,752
	c. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Total Jurisdictional ECRC Costs		$2,961,334	$3,029,101	$3,560,223	$3,227,696	$3,522,648	$2,976,415	$3,705,394	$3,707,401	$3,774,850	$4,188,595	$2,761,237	$3,492,785	$40,907,679
5	Over/(Under) Recovery (Line 3 - Line 4d)		$636,521	$578,806	$169,592	$832,985	$338,641	$1,243,831	$945,363	$865,813	$793,496	$52,606	$1,350,497	$435,166	$8,243,316
6	Interest Provision (Form 42-3A, Line 10)		22,965	20,588	22,482	12,624	740	926	1,111	1,046	779	603	776	710	85,350
7	Beginning Balance True-Up & Interest Provision		18,654,948	17,759,855	16,804,670	15,442,165	14,733,195	13,517,997	13,208,175	12,600,069	11,912,349	11,152,045	9,650,675	9,447,369	18,654,948
	a. Deferred True-Up - January 2019 - December 2019 (2019 TU filing dated April 1, 2020)		(1,792,439)	(1,792,439)	(1,792,439)	(1,792,439)	(1,792,439)	(1,792,439)	(1,792,439)	(1,792,439)	(1,792,439)	(1,792,439)	(1,792,439)	(1,792,439)	(1,792,439)
8	True-Up Collected/(Refunded) (see Line 2)		(1,554,579)	(1,554,579)	(1,554,579)	(1,554,579)	(1,554,579)	(1,554,579)	(1,554,579)	(1,554,579)	(1,554,579)	(1,554,579)	(1,554,579)	(1,554,579)	(18,654,948)
9	End of Period Total True-Up (Lines 5+6+7+7a+8)		$15,967,416	$15,012,231	$13,649,725	$12,940,755	$11,725,558	$11,415,735	$10,807,630	$10,119,910	$9,359,606	$7,858,236	$7,654,930	$6,536,227	$6,536,227
10	Adjustments to Period Total True-Up Including Interest		0	0	0	0	0	0	0	0	0	0	0	0	0
11	End of Period Total True-Up Over/(Under) (Lines 9 + 10)		$15,967,416	$15,012,231	$13,649,725	$12,940,755	$11,725,558	$11,415,735	10,807,630	$10,119,910	$9,359,606	$7,858,236	$7,654,930	$6,536,227	$6,536,227

Notes:
(A) N/A

Form 42-3A

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2020 - December 2020

Docket No. 20210007-EI
Duke Energy Florida
Witness: G. P. Dean
Exh. No. __ (GPD-1)

Interest Provision
(in Dollars)

Line	Description	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	Beginning True-Up Amount (Form 42-2A, Line 7 + 7a + 10)	$16,862,509	$15,967,416	$15,012,231	$13,649,725	$12,940,755	$11,725,558	$11,415,735	$10,807,630	$10,119,910	$9,359,606	$7,858,236	$7,654,930	
2	Ending True-Up Amount Before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	15,944,451	14,991,643	13,627,243	12,928,131	11,724,818	11,414,809	10,806,519	10,118,864	9,358,827	7,857,633	7,654,154	6,535,517	
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	32,806,960	30,959,059	28,639,474	26,577,857	24,665,573	23,140,367	22,222,254	20,926,494	19,478,737	17,217,239	15,512,390	14,190,447	
4	Average True-Up Amount (Line 3 x 1/2)	16,403,480	15,479,530	14,319,737	13,288,929	12,332,787	11,570,184	11,111,127	10,463,247	9,739,369	8,608,620	7,756,195	7,095,224	
5	Interest Rate (Last Business Day of Prior Month)	1.71%	1.64%	1.56%	2.21%	0.06%	0.08%	0.11%	0.12%	0.11%	0.07%	0.10%	0.14%	
6	Interest Rate (Last Business Day of Current Month)	1.64%	1.56%	2.21%	0.06%	0.08%	0.11%	0.12%	0.11%	0.07%	0.10%	0.14%	0.10%	
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	3.35%	3.20%	3.77%	2.27%	0.14%	0.19%	0.23%	0.23%	0.18%	0.17%	0.24%	0.24%	
8	Average Interest Rate (Line 7 x 1/2)	1.675%	1.600%	1.885%	1.135%	0.070%	0.095%	0.115%	0.115%	0.090%	0.085%	0.120%	0.120%	
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.140%	0.133%	0.157%	0.095%	0.006%	0.008%	0.010%	0.010%	0.008%	0.007%	0.010%	0.010%	
10	Interest Provision for the Month (Line 4 x Line 9)	$22,965	$20,588	$22,482	$12,624	$740	$926	$1,111	$1,046	$779	$603	$776	$710	$85,350

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2020 - December 2020

Variance Report of O&M Activities
(In Dollars)

Line			(1) YTD Actual	(2) Actual/ Estimated	(3) Variance Amount	(4) Variance Percent
1	Description of O&M Activities - System					
	1	Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$37,685	$12,640	$25,045	198%
	1a	Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	157	157	0	0%
	2	Distribution System Environmental Investigation, Remediation, and Pollution Prevention	0	0	0	0%
	3	Pipeline Integrity Management - Bartow /Anclote Pipeline - Intm	0	0	0	0%
	4	Above Ground Tank Secondary Containment	0	0	0	0%
	5	SO2/NOx Emissions Allowances - Energy	6,011	3,470	2,541	73%
	6	Phase II Cooling Water Intake 316(b) - Base	167,575	156,740	10,834	7%
	6a	Phase II Cooling Water Intake 316(b) - Intm	169,570	148,387	21,183	14%
	7.2	CAIR/CAMR - Peaking - Demand	0	0	0	0%
	7.4	CAIR/CAMR Crystal River - Base	11,839,103	10,946,197	892,906	8%
	7.4	CAIR/CAMR Crystal River - Energy	3,475,420	4,253,088	(777,668)	-18%
	7.4	CAIR/CAMR Crystal River - A&G	67,656	68,946	(1,290)	-2%
	7.4	CAIR/CAMR Crystal River - Conditions of Certification - Energy	943,995	983,194	(39,200)	-4%
	7.5	Best Available Retrofit Technology (BART) - Energy	0	0	0	0%
	8	Arsenic Groundwater Standard - Base	285,256	1,234,899	(949,643)	-77%
	9	Sea Turtle - Coastal Street Lighting - Distrib	0	0	0	0%
	11	Modular Cooling Towers - Base	0	0	0	0%
	12	Greenhouse Gas Inventory and Reporting - Energy	0	0	0	0%
	13	Mercury Total Daily Maximum Loads Monitoring - Energy	0	0	0	0%
	14	Hazardous Air Pollutants (HAPs) ICR Program - Energy	0	0	0	0%
	15	Effluent Limitation Guidelines ICR Program - Energy	0	0	0	0%
	15.1	Effluent Limitation Guidelines Program CRN - Energy	0	0	0	0%
	16	National Pollutant Discharge Elimination System (NPDES) - Energy	4,047	29,840	(25,793)	-86%
	17	Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy	31,543	121,543	(90,000)	-74%
	17.1	Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion - Energy	0	0	0	0%
	17.2	Mercury & Air Toxic Standards (MATS) CR1 & CR2 - Energy	0	0	0	0%
	18	Coal Combustion Residual (CCR) Rule - Energy	665,377	917,228	(251,850)	-27%
2	Total O&M Activities - Recoverable Costs		$17,693,394	$18,876,329	($1,182,935)	-6%
3	Recoverable Costs Allocated to Energy		5,126,393	6,308,363	(1,181,970)	-19%
4	Recoverable Costs Allocated to Demand		12,567,001	12,567,966	(965)	0%

Notes:
Column (1) End of Period Totals on Form 42-5A
Column (2) 2020 Actual/Estimated Filing (7/31/2020)
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2020 - December 2020

O&M Activities
(in Dollars)

Line		Description	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1		Description of O&M Activities													
	1	Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$1,296	$1,105	($374)	$308	$649	$338	$3,889	$4,999	$3,164	$2,378	$8,777	$11,157	$37,685
	1a	Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	0	0	374	0	(217)	0	0	0	0	0	0	0	157
	2	Distribution System Environmental Investigation, Remediation, and Pollution Prevention	0	0	0	0	0	0	0	0	0	0	0	0	0
	3	Pipeline Integrity Management - Bartow/Anclote Pipeline - Intm	0	0	0	0	0	0	0	0	0	0	0	0	0
	4	Above Ground Tank Secondary Containment - Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0
	5	SO2/NOx Emissions Allowances - Energy	261	212	9	(2,046)	0	0	800	1,426	1,452	0	0	3,897	6,011
	6	Phase II Cooling Water Intake 316(b) - Base	27,135	26,151	4,746	2,053	77,067	13,988	3,641	12,793	0	0	0	0	167,575
	6a	Phase II Cooling Water Intake 316(b) - Intm	16,471	20,958	18,535	102,551	(24,211)	8,783	5,277	20,204	0	1,003	0	0	169,570
	7.2	CAIR/CAMR - Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0
	7.4	CAIR/CAMR Crystal River - Base	1,105,292	736,840	1,254,794	861,583	970,700	816,988	976,127	1,061,364	1,028,376	1,062,031	943,239	1,021,769	11,839,103
	7.4	CAIR/CAMR Crystal River - Energy	(3,673)	0	41,720	112,935	365,231	325,023	607,587	485,069	473,300	1,274,380	(260,233)	54,081	3,475,420
	7.4	CAIR/CAMR Crystal River - A&G	3,425	5,372	7,259	6,025	6,053	4,511	5,435	8,515	4,515	6,527	5,187	4,831	67,656
	7.4	CAIR/CAMR Crystal River - Conditions of Certification - Energy	56,978	29,604	12,134	46,552	83,072	54,855	69,489	71,246	91,730	181,267	206,007	41,062	943,995
	7.5	Best Available Retrofit Technology (BART) - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	8	Arsenic Groundwater Standard - Base	1,640	4,843	14,781	28,599	16,036	0	0	96,544	142,429	6,773	0	(26,388)	285,256
	9	Sea Turtle - Coastal Street Lighting - Distrib	0	0	0	0	0	0	0	0	0	0	0	0	0
	11	Modular Cooling Towers - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
	12	Greenhouse Gas Inventory and Reporting - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	13	Mercury Total Daily Maximum Loads Monitoring - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	14	Hazardous Air Pollutants (HAPs) ICR Program - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	15	Effluent Limitation Guidelines ICR Program - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	15.1	Effluent Limitation Guidelines ICR Program CRN - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	16	National Pollutant Discharge Elimination System (NPDES) - Energy	623	(7,733)	0	0	4,691	0	0	6,467	0	0	0	0	4,047
	17	Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy	0	0	5,666	25,876	0	0	0	0	0	0	0	0	31,543
	17.1	Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	17.2	Mercury & Air Toxic Standards (MATS) CR1 & CR2 - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	18	Coal Combustion Residual (CCR) Rule - Energy	48,182	151,265	222,440	45,648	89,889	(224,212)	142,870	44,591	100,952	(220,035)	(196,875)	460,661	665,377
2		Total of O&M Activities	$1,257,630	$968,617	$1,582,085	$1,230,083	$1,588,960	$1,000,274	$1,815,115	$1,813,217	$1,845,918	$2,314,323	$706,103	$1,571,069	$17,693,394
3		Recoverable Costs Allocated to Energy	102,371	173,348	281,970	228,964	542,883	155,666	820,746	608,799	667,434	1,235,612	(251,100)	559,700	5,126,393
4		Recoverable Costs Allocated to Demand - Transm	1,296	1,105	(374)	308	649	338	3,889	4,999	3,164	2,378	8,777	11,157	37,685
		Recoverable Costs Allocated to Demand - Distrib	0	0	374	0	(217)	0	0	0	0	0	0	0	157
		Recoverable Costs Allocated to Demand - Prod-Base	1,134,067	767,834	1,274,321	892,235	1,063,803	830,976	979,768	1,170,700	1,170,805	1,068,804	943,239	995,381	12,291,934
		Recoverable Costs Allocated to Demand - Prod-Intm	16,471	20,958	18,535	102,551	(24,211)	8,783	5,277	20,204	0	1,003	0	0	169,570
		Recoverable Costs Allocated to Demand - Prod-Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0
		Recoverable Costs Allocated to Demand - A&G	3,425	5,372	7,259	6,025	6,053	4,511	5,435	8,515	4,515	6,527	5,187	4,831	67,656
5		Retail Energy Jurisdictional Factor	0.97570	0.97330	0.94540	0.95410	0.91520	0.91350	0.90640	0.90730	0.92460	0.91720	0.95210	0.92960	
6		Retail Transmission Demand Jurisdictional Factor	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	
		Retail Distribution Demand Jurisdictional Factor	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	
		Retail Production Demand Jurisdictional Factor - Base	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
		Retail Production Demand Jurisdictional Factor - Intm	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
		Retail Production Demand Jurisdictional Factor - Peaking	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	
		Retail Production Demand Jurisdictional Factor - A&G	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	
7		Jurisdictional Energy Recoverable Costs (A)	99,884	168,719	266,574	218,455	496,846	142,201	743,924	552,363	617,110	1,133,303	(239,073)	520,297	4,720,603
8		Jurisdictional Demand Recoverable Costs - Transm (B)	909	775	(263)	216	456	237	2,730	3,510	2,221	1,669	6,162	7,832	26,454
		Jurisdictional Demand Recoverable Costs - Distrib (B)	0	0	372	0	(216)	0	0	0	0	0	0	0	156
		Jurisdictional Demand Recoverable Costs - Prod-Base (B)	1,053,378	713,202	1,183,653	828,753	988,114	771,852	910,058	1,087,405	1,087,502	992,759	876,128	924,560	11,417,364
		Jurisdictional Demand Recoverable Costs - Prod-Intm (B)	11,975	15,237	13,476	74,557	(17,602)	6,385	3,836	14,689	0	729	0	0	123,282
		Jurisdictional Demand Recoverable Costs - Prod-Peaking (B)	0	0	0	0	0	0	0	0	0	0	0	0	0
		Jurisdictional Demand Recoverable Costs - A&G (B)	3,193	5,008	6,767	5,616	5,643	4,205	5,066	7,938	4,209	6,085	4,835	4,503	63,068
9		Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$1,169,339	$902,941	$1,470,579	$1,127,597	$1,473,241	$924,880	$1,665,614	$1,665,905	$1,711,042	$2,134,545	$648,052	$1,457,192	$16,350,927

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2020 - December 2020

Variance Report of Capital Investment Activities
(In Dollars)

Line			(1) Total Year Actual	(2) Actual/ Estimated	(3) Variance Amount	(4) Variance Percent
1	Description of Capital Investment Activities					
	3.1	Pipeline Integrity Management - Bartow/Anclote Pipeline	$0	$0	$0	0%
	4.x	Above Ground Tank Secondary Containment	1,194,688	1,199,345	(4,656)	0%
	5	SO2/NOx Emissions Allowances	247,412	247,445	(33)	0%
	6	Phase II Cooling Water Intake 316(b)	652,486	693,553	(41,067)	-6%
	7.x	CAIR/CAMR	8,359,640	8,264,611	95,029	1%
	9	Sea Turtle - Coastal Street Lighting	955	955	0	0%
	10.x	Underground Storage Tanks	20,543	20,543	0	0%
	11	Modular Cooling Towers	0	0	0	0%
	11.1	Crystal River Thermal Discharge Compliance Project	0	0	0	0%
	15.1	Effluent Limitation Guidelines CRN (ELG)	235,548	242,978	(7,430)	-3%
	16	National Pollutant Discharge Elimination System (NPDES)	1,318,202	1,318,202	0	0%
	17x	Mercury & Air Toxics Standards (MATS)	14,516,034	14,573,654	(57,620)	0%
	18	Coal Combustion Residual (CCR) Rule	61,487	63,447	(1,960)	-3%
2	Total Capital Investment Activities - Recoverable Costs		$26,606,996	$26,624,734	($17,738)	0%
3	Recoverable Costs Allocated to Energy		14,910,324	14,864,768	$45,556	0%
4	Recoverable Costs Allocated to Demand		$11,696,672	$11,759,966	($63,294)	-1%

Notes:
Column (1) End of Period Totals on Form 42-7A
Column (2) 2020 Actual/Estimated Filing (7/31/2020)
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2020 - December 2020

Capital Investment Projects-Recoverable Costs
(in Dollars)

Form 42-7A

Docket No. 20210007-EI
Duke Energy Florida
Witness: G. P. Dean
Exh. No. __ (GPD-1)
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Line	Description	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	Description of Investment Projects (A)													
3.1	Pipeline Integrity Management - Bartow/Anclote Pipeline - Intermediate	$0	$0	$0	$0	$0	$0	0	$0	$0	$0	$0	$0	$0
4.1	Above Ground Tank Secondary Containment - Peaking	64,541	81,264	81,003	80,744	80,487	80,229	79,923	79,664	79,404	79,148	83,432	83,142	952,981
4.2	Above Ground Tank Secondary Containment - Base	17,686	18,380	18,360	18,341	18,320	18,302	18,262	18,241	18,222	18,204	18,184	18,165	218,667
4.3	Above Ground Tank Secondary Containment - Intermediate	1,399	1,986	1,982	1,979	1,975	1,972	1,967	1,963	1,960	1,956	1,953	1,949	23,041
5	SO2/NOX Emissions Allowances - Energy	20,634	20,633	20,633	20,639	20,645	20,645	20,614	20,606	20,597	20,593	20,593	20,580	247,412
6	Phase II Cooling Water Intake 316(b) - Base	39,947	44,336	46,728	49,034	51,191	53,660	55,431	58,357	61,065	62,497	64,469	65,771	652,486
7.1	CAIR/CAMR Anclote- Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0
7.2	CAIR/CAMR - Peaking	29,902	31,736	31,590	31,446	31,302	31,159	31,003	30,861	30,714	30,569	38,611	38,414	387,310
7.3	CAMR Crystal River - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
7.4	CAIR/CAMR Crystal River AFUDC - Base	640,701	657,101	656,393	655,690	654,984	654,281	652,807	652,105	651,401	650,698	649,997	649,294	7,825,452
7.4	CAIR/CAMR Crystal River AFUDC - Energy	11,110	11,121	11,106	11,134	10,799	10,581	11,260	12,186	13,026	13,770	14,678	16,107	146,878
7.5	Best Available Retrofit Technology (BART) - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Sea Turtle - Coastal Street Lighting -Distribution	60	82	82	82	82	82	81	81	81	81	81	80	955
10.1	Underground Storage Tanks - Base	1,294	1,178	1,175	1,174	1,171	1,170	1,167	1,165	1,163	1,162	1,159	1,158	14,136
10.2	Underground Storage Tanks - Intermediate	447	548	547	546	544	543	542	541	539	538	537	535	6,407
11	Modular Cooling Towers - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
15.1	Effluent Limitation Guidelines CRN (RLG) - Base	15,621	15,839	16,029	16,390	16,784	22,480	22,356	22,073	22,039	22,007	21,979	21,951	235,548
16	National Pollutant Discharge Elimination System (NPDES) - Intermediate	94,393	112,447	112,220	111,991	111,763	111,535	111,212	110,983	110,756	110,528	110,301	110,073	1,318,202
17	Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy	25,770	27,465	27,423	27,381	27,338	27,297	27,225	27,182	27,140	27,099	27,056	27,054	325,433
17.1	Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion - Energy	760,385	1,041,223	1,039,673	1,038,124	1,036,573	1,035,024	1,032,426	1,030,878	1,029,330	1,027,783	1,026,235	1,024,687	12,122,336
17.2	Mercury & Air Toxic Standards (MATS) CR1 & CR2 - Energy	169,977	180,141	179,693	179,246	178,799	178,351	177,737	177,291	176,844	176,397	175,951	117,841	2,068,264
18	Coal Combustion Residual (CCR) Rule - Demand	3,385	3,541	3,536	3,530	3,526	3,521	3,767	4,156	4,412	5,197	8,697	14,220	61,487
2	Total Investment Projects - Recoverable Costs	$1,897,251	$2,249,022	$2,248,174	$2,247,472	$2,246,284	$2,250,833	$2,247,780	$2,248,333	$2,248,693	$2,248,227	$2,263,911	$2,211,019	$26,606,996
3	Recoverable Costs Allocated to Energy	987,875	1,280,583	1,278,528	1,276,524	1,274,154	1,271,898	1,269,262	1,268,143	1,266,937	1,265,642	1,264,513	1,206,269	14,910,324
	Recoverable Costs Allocated to Distribution Demand	60	82	82	82	82	82	81	81	81	81	81	80	955
4	Recoverable Costs Allocated to Demand - Production - Base	718,633	740,375	742,221	744,159	745,976	753,414	753,790	756,097	758,302	759,765	764,485	770,559	9,007,776
	Recoverable Costs Allocated to Demand - Production - Intermediate	96,239	114,981	114,749	114,516	114,282	114,050	113,721	113,487	113,255	113,022	112,791	112,557	1,347,650
	Recoverable Costs Allocated to Demand - Production - Peaking	94,443	113,000	112,593	112,190	111,789	111,388	110,926	110,525	110,118	109,717	122,042	121,555	1,340,291
5	Retail Energy Jurisdictional Factor	0.97570	0.97330	0.94540	0.95410	0.91520	0.91350	0.90640	0.90730	0.92460	0.91720	0.95210	0.92960	
	Retail Distribution Demand Jurisdictional Factor	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	
6	Retail Demand Jurisdictional Factor - Production - Base	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
	Retail Demand Jurisdictional Factor - Production - Intermediate	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
	Retail Demand Jurisdictional Factor - Production - Peaking	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	
7	Jurisdictional Energy Recoverable Costs (B)	963,870	1,246,391	1,208,720	1,217,931	1,166,105	1,161,878	1,150,459	1,150,586	1,171,410	1,160,846	1,203,942	1,121,347	13,923,486
	Jurisdictional Demand Recoverable Costs - Distribution (B)	60	82	82	82	82	82	81	81	81	81	81	80	951
8	Jurisdictional Demand Recoverable Costs - Production - Base (C)	667,503	687,698	689,412	691,213	692,900	699,809	700,157	702,300	704,348	705,707	710,091	715,733	8,366,873
	Jurisdictional Demand Recoverable Costs - Production - Intermediate (C)	69,969	83,595	83,426	83,257	83,086	82,918	82,679	82,508	82,340	82,170	82,002	81,832	979,782
	Jurisdictional Demand Recoverable Costs - Production - Peaking (C)	90,594	108,395	108,004	107,618	107,233	106,848	106,405	106,020	105,630	105,245	117,068	116,601	1,285,661
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$1,791,995	$2,126,160	$2,089,644	$2,100,099	$2,049,407	$2,051,535	$2,039,780	$2,041,496	$2,063,808	$2,054,050	$2,113,185	$2,035,593	$24,556,752

Notes:

(A) Each project's Total System Recoverable Expenses on Form 42-8A, Line 9; Form 42-8A, Line 5 for Projects 5 - Emission Allowances and Project 7. 4 - Reagents
(B) Line 3 x Line 5
(C) Line 4 x Line 6

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
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Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Peaking (Project 4.1)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	178,938	0	0	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$8,840,236	$8,840,236	$8,840,236	$8,840,236	$8,840,236	$8,840,236	$8,840,236	$8,840,236	$8,840,236	$8,840,236	$8,661,298	$8,661,298	$8,661,298	
3	Less: Accumulated Depreciation			(3,522,436)	(3,548,728)	(3,575,020)	(3,601,312)	(3,627,604)	(3,653,896)	(3,680,188)	(3,706,479)	(3,732,771)	(3,759,063)	(3,606,417)	(3,696,690)	(3,722,253)	
3a	Regulatory Asset Balance (G)			169,932	155,771	141,610	127,449	113,288	99,127	84,966	70,805	56,644	42,483	28,322	73,467	53,915	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$5,487,731	$5,447,279	$5,406,826	$5,366,373	$5,325,920	$5,285,467	$5,245,015	$5,204,562	$5,164,109	$5,123,656	$5,083,203	$5,038,075	$4,992,960	
6	Average Net Investment				$5,467,505	$5,427,052	$5,386,599	$5,346,147	$5,305,694	$5,265,241	$5,224,788	$5,184,335	$5,143,883	$5,103,430	$5,060,639	$5,015,518	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.97%	1.89%		8,960	8,895	8,827	8,761	8,696	8,629	8,234	8,171	8,106	8,044	7,976	7,903	101,202
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		25,997	25,805	25,612	25,419	25,227	25,036	25,125	24,929	24,734	24,540	24,335	24,118	300,877
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)				26,292	26,292	26,292	26,292	26,292	26,292	26,292	26,292	26,292	26,292	25,576	25,576	314,070
	b. Amortization (G)				14,161	14,161	14,161	14,161	14,161	14,161	14,161	14,161	14,161	14,161	19,552	19,552	180,714
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)				(10,869)	6,111	6,111	6,111	6,111	6,111	6,111	6,111	6,111	6,111	5,992	5,992	56,117
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$64,541	$81,264	$81,003	$80,744	$80,487	$80,229	$79,923	$79,664	$79,404	$79,148	$83,432	$83,142	952,981
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$64,541	$81,264	$81,003	$80,744	$80,487	$80,229	$79,923	$79,664	$79,404	$79,148	$83,432	$83,142	952,981
10	Energy Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Peaking)				0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	
12	Retail Energy-Related Recoverable Costs (E)				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)				61,911	77,952	77,701	77,453	77,206	76,959	76,665	76,417	76,168	75,922	80,031	79,753	914,137
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$61,911	$77,952	$77,701	$77,453	$77,206	$76,959	$76,665	$76,417	$76,168	$75,922	$80,031	$79,753	$914,137

Notes:
(A) N/A
(B) Jan - Jun 2020 Line 6 x 7.67% x 1/12. Jul - Dec 2020 Line 6 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.
(C) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed in service. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed in service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.
(E) Line 9a x Line 10
(F) Line 9b x Line 11
(G) Projects 4.1d (Avon Park AST) and 4.1i (Higgins AST) amortized over one year as approved in Order No. PSC-2019-0500-FOF-EI.

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2020 - December 2020

Docket No. 20210007-EI
Duke Energy Florida
Witness: G. P. Dean
Exh. No. __ (GPD-1)

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Base (Project 4.2)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$2,399,039	$2,399,039	$2,399,039	$2,399,039	$2,399,039	$2,399,039	$2,399,039	$2,399,039	$2,399,039	$2,399,039	$2,399,039	$2,399,039	$2,399,039	
3	Less: Accumulated Depreciation			(45,535)	(48,567)	(51,599)	(54,631)	(57,663)	(60,695)	(63,727)	(66,759)	(69,791)	(72,823)	(75,855)	(78,887)	(81,919)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$2,353,504	$2,350,472	$2,347,440	$2,344,408	$2,341,376	$2,338,344	$2,335,312	$2,332,280	$2,329,248	$2,326,216	$2,323,184	$2,320,152	$2,317,120	
6	Average Net Investment				$2,351,988	$2,348,956	$2,345,924	$2,342,892	$2,339,860	$2,336,828	$2,333,796	$2,330,764	$2,327,732	$2,324,700	$2,321,668	$2,318,636	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.97%	1.89%		3,855	3,850	3,845	3,840	3,834	3,830	3,678	3,673	3,668	3,664	3,659	3,654	45,050
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		11,183	11,169	11,154	11,140	11,125	11,111	11,223	11,207	11,193	11,179	11,164	11,150	133,998
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)				3,032	3,032	3,032	3,032	3,032	3,032	3,032	3,032	3,032	3,032	3,032	3,032	36,384
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				0	0	0	0	0	0	0	0	0	0	0	0	N/A
	d. Property Taxes (D)				(384)	329	329	329	329	329	329	329	329	329	329	329	3,235
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$17,686	$18,380	$18,360	$18,341	$18,320	$18,302	$18,262	$18,241	$18,222	$18,204	$18,184	$18,165	218,667
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$17,686	$18,380	$18,360	$18,341	$18,320	$18,302	$18,262	$18,241	$18,222	$18,204	$18,184	$18,165	218,667
10	Energy Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)				0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)				16,427	17,072	17,054	17,036	17,017	17,000	16,963	16,943	16,926	16,909	16,890	16,873	203,109
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$16,427	$17,072	$17,054	$17,036	$17,017	$17,000	$16,963	$16,943	$16,926	$16,909	$16,890	$16,873	$203,109

Notes:
(A) N/A
(B) Jan - Jun 2020 Line 6 x 7.67% x 1/12. Jul - Dec 2020 Line 6 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.
(C) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 rate case Order PSC-2010-0131-FOF-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2020 - December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Intermediate (Project 4.3)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	
3	Less: Accumulated Depreciation			(85,386)	(85,911)	(86,436)	(86,961)	(87,486)	(88,011)	(88,536)	(89,061)	(89,586)	(90,111)	(90,636)	(91,161)	(91,686)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$204,911	$204,386	$203,861	$203,336	$202,811	$202,286	$201,761	$201,236	$200,711	$200,186	$199,661	$199,136	$198,611	
6	Average Net Investment				$204,649	$204,124	$203,599	$203,074	$202,549	$202,024	$201,499	$200,974	$200,449	$199,924	$199,399	$198,874	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.97%	1.89%		335	335	334	333	332	331	318	317	316	315	314	313	3,893
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		973	971	968	966	963	961	969	966	964	961	959	956	11,577
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)				525	525	525	525	525	525	525	525	525	525	525	525	6,300
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)				(434)	155	155	155	155	155	155	155	155	155	155	155	1,271
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$1,399	$1,986	$1,982	$1,979	$1,975	$1,972	$1,967	$1,963	$1,960	$1,956	$1,953	$1,949	23,041
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$1,399	$1,986	$1,982	$1,979	$1,975	$1,972	$1,967	$1,963	$1,960	$1,956	$1,953	$1,949	23,041
10	Energy Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)				0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
12	Retail Energy-Related Recoverable Costs (E)				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)				1,017	1,444	1,441	1,439	1,436	1,434	1,430	1,427	1,425	1,422	1,420	1,417	16,751
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$1,017	$1,444	$1,441	$1,439	$1,436	$1,434	$1,430	$1,427	$1,425	$1,422	$1,420	$1,417	$16,751

Notes:
(A) N/A
(B) Jan - Jun 2020 Line 6 x 7.67% x 1/12. Jul - Dec 2020 Line 6 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.
(C) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
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Form 42-8A
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Docket No. 20210007-EI
Duke Energy Florida
Witness: G. P. Dean
Exh. No. __ (GPD-1)
Page 12 of 26

SO2 and NOx EMISSIONS ALLOWANCES - Energy (Project 5)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	Working Capital Dr (Cr)																
	a. 0158150 SO2 Emission Allowance Inventory			$3,227,480	$3,227,222	$3,227,010	$3,227,001	$3,229,047	$3,229,047	$3,229,047	$3,228,247	$3,226,821	$3,225,369	$3,225,369	$3,225,369	$3,221,472	$3,221,472
	b. 0254020 Auctioned SO2 Allowance			0	0	0	0	0	0	0	0	0	0	0	0	0	$0
	c. 0158170 NOx Emission Allowance Inventory			0	0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Total Working Capital			$3,227,480	$3,227,222	$3,227,010	$3,227,001	$3,229,047	$3,229,047	$3,229,047	$3,228,247	$3,226,821	$3,225,369	$3,225,369	$3,225,369	$3,221,472	$3,221,472
3	Average Net Investment				$3,227,351	$3,227,116	$3,227,005	$3,228,024	$3,229,047	$3,229,047	$3,228,647	$3,227,534	$3,226,095	$3,225,369	$3,225,369	$3,223,420	
4	Return on Average Net Working Capital Balance (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.97%	1.89%		5,289	5,289	5,289	5,290	5,292	5,292	5,088	5,086	5,084	5,083	5,083	5,080	62,245
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		15,345	15,344	15,344	15,349	15,353	15,353	15,526	15,520	15,513	15,510	15,510	15,500	185,167
5	Total Return Component (C)				$20,634	$20,633	$20,633	$20,639	$20,645	$20,645	$20,614	$20,606	$20,597	$20,593	$20,593	$20,580	247,412
6	Expense Dr (Cr)																
	a. 0509030 SO_2 Allowance Expense				$261	$212	$9	($2,046)	$0	$0	$800	$1,426	$1,452	$0	$0	$3,897	$6,011
	b. 0407426 Amortization Expense				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
	c. 0509212 NOx Allowance Expense				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
	d. Other				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
7	Net Expense (D)				261	212	9	(2,046)	0	0	800	1,426	1,452	0	0	3,897	6,011
8	Total System Recoverable Expenses (Lines 5 + 7 + 8)				$20,895	$20,845	$20,642	$18,593	$20,645	$20,645	$21,414	$22,032	$22,049	$20,593	$20,593	$24,477	253,423
	a. Recoverable Costs Allocated to Energy				20,895	20,845	20,642	18,593	20,645	20,645	21,414	22,032	22,049	20,593	20,593	24,477	253,423
	b. Recoverable Costs Allocated to Demand				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
9	Energy Jurisdictional Factor				0.97570	0.97330	0.94540	0.95410	0.91520	0.91350	0.90640	0.90730	0.92460	0.91720	0.95210	0.92960	
10	Demand Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Retail Energy-Related Recoverable Costs (E)				$20,387	$20,288	$19,515	$17,740	$18,894	$18,859	$19,409	$19,990	$20,387	$18,888	$19,607	$22,754	236,717
12	Retail Demand-Related Recoverable Costs (F)				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$20,387	$20,288	$19,515	$17,740	$18,894	$18,859	$19,409	$19,990	$20,387	$18,888	$19,607	$22,754	$236,717

Notes:
(A) N/A
(B) Jan - Jun 2020 Line 3 x 7.67% x 1/12. Jul - Dec 2020 Line 3 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.
(C) Line 5 is reported on Capital Schedule
(D) Line 7 is reported on O&M Schedule
(E) Line 8a x Line 9
(F) Line 8b x Line 10

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2020 - December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Phase II Cooling Water Intake 316(b) - Base (Project 6)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	Investments														
	a. Expenditures/Additions		$1,112,889	$260,143	$488,106	$233,259	$441,164	$331,194	$247,932	$668,645	$179,174	$269,704	$348,128	$59,738	$4,640,077
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing	5,691,363	6,804,252	7,064,395	7,552,501	7,785,760	8,226,924	8,558,118	8,806,050	9,474,696	9,653,869	9,923,574	10,271,702	10,331,440	
5	Net Investment (Lines 2 + 3 + 4)	$5,691,363	$6,804,252	$7,064,395	$7,552,501	$7,785,760	$8,226,924	$8,558,118	$8,806,050	$9,474,696	$9,653,869	$9,923,574	$10,271,702	$10,331,440	
6	Average Net Investment		$6,247,807	$6,934,324	$7,308,448	$7,669,131	$8,006,342	$8,392,521	$8,682,084	$9,140,373	$9,564,283	$9,788,722	$10,097,638	$10,301,571	
7	Return on Average Net Investment (B) — Jan-Jun / Jul-Dec														
	a. Debt Component 1.97% / 1.89%		10,240	11,365	11,978	12,569	13,122	13,755	13,682	14,404	15,073	15,426	15,913	16,234	163,761
	b. Equity Component Grossed Up For Taxes 5.71% / 5.77%		29,707	32,971	34,750	36,465	38,069	39,905	41,749	43,953	45,992	47,071	48,556	49,537	488,725
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation (C) 1.4860%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D) 0.000525		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		$39,947	$44,336	$46,728	$49,034	$51,191	$53,660	$55,431	$58,357	$61,065	$62,497	$64,469	$65,771	652,486
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		$39,947	$44,336	$46,728	$49,034	$51,191	$53,660	$55,431	$58,357	$61,065	$62,497	$64,469	$65,771	652,486
10	Energy Jurisdictional Factor		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor		0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)		37,105	41,181	43,403	45,545	47,549	49,842	51,487	54,205	56,720	58,050	59,882	61,091	606,062
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$37,105	$41,181	$43,403	$45,545	$47,549	$49,842	$51,487	$54,205	$56,720	$58,050	$59,882	$61,091	$606,062

Notes:
(A) N/A
(B) Jan - Jun 2020 Line 3 x 7.67% x 1/12. Jul - Dec 2020 Line 3 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2020 - December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Peaking (Project 7.2 - CT Emission Monitoring Systems)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	161,754	0	0	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$1,454,898	$1,454,898	$1,454,898	$1,454,898	$1,454,898	$1,454,898	$1,454,898	$1,454,898	$1,454,898	$1,454,898	$1,293,144	$1,293,144	$1,293,144	
3	Less: Accumulated Depreciation			(385,464)	(388,039)	(390,614)	(393,189)	(395,764)	(398,339)	(400,914)	(403,489)	(406,064)	(408,639)	(249,460)	(356,312)	(358,483)	
3a	Regulatory Asset Balance (G)			239,885	219,894	199,904	179,914	159,923	139,933	119,942	99,952	79,962	59,971	39,981	115,948	87,234	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$1,309,319	$1,286,754	$1,264,188	$1,241,623	$1,219,057	$1,196,492	$1,173,927	$1,151,361	$1,128,796	$1,106,230	$1,083,665	$1,052,780	$1,021,895	
6	Average Net Investment				$1,298,036	$1,275,471	$1,252,905	$1,230,340	$1,207,775	$1,185,209	$1,162,644	$1,140,078	$1,117,513	$1,094,948	$1,068,223	$1,037,338	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.97%	1.89%		2,128	2,091	2,053	2,016	1,979	1,943	1,831	1,797	1,761	1,725	1,683	1,635	22,642
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		6,172	6,065	5,957	5,850	5,743	5,636	5,592	5,484	5,373	5,264	5,136	4,987	67,259
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)	Varies			2,575	2,575	2,575	2,575	2,575	2,575	2,575	2,575	2,575	2,575	2,171	2,171	30,092
	b. Amortization (G)				19,990	19,990	19,990	19,990	19,990	19,990	19,990	19,990	19,990	19,990	28,714	28,714	257,332
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	Varies			(964)	1,015	1,015	1,015	1,015	1,015	1,015	1,015	1,015	1,015	907	907	9,985
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$29,902	$31,736	$31,590	$31,446	$31,302	$31,159	$31,003	$30,861	$30,714	$30,569	$38,611	$38,414	387,310
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$29,902	$31,736	$31,590	$31,446	$31,302	$31,159	$31,003	$30,861	$30,714	$30,569	$38,611	$38,414	387,310
10	Energy Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Peaking)				0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	
12	Retail Energy-Related Recoverable Costs (E)				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)				28,683	30,443	30,303	30,165	30,027	29,889	29,740	29,603	29,462	29,323	37,037	36,848	371,523
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$28,683	$30,443	$30,303	$30,165	$30,027	$29,889	$29,740	$29,603	$29,462	$29,323	$37,037	$36,848	$371,523

Notes:
(A) N/A
(B) Jan - Jun 2020 Line 3 x 7.67% x 1/12. Jul - Dec 2020 Line 3 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.
(C) Depreciation calculated in Pipeline Integrity Management section of Capital Program Detail file only on assets placed in service. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Property tax calculated in Pipeline Integrity Management section of Capital Program Detail file only on assets placed in-service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.
(E) Line 9a x Line 10
(F) Line 9b x Line 11
(G) Projects 4.1d (Avon Park AST) and 4.1i (Higgins AST) amortized over one year as approved in Order No. PSC-2019-0500-FOF-EI.

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2020 - December 2020

Docket No. 20210007-EI
Duke Energy Florida
Witness: G. P. Dean
Exh. No. __ (GPD-1)

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Base (Project 7.4 - Crystal River)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$159,014	($1,299)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$157,716
	b. Clearings to Plant				159,014	(1,299)	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$86,541,985	$86,701,000	$86,699,701	$86,699,701	$86,699,701	$86,699,701	$86,699,701	$86,699,701	$86,699,701	$86,699,701	$86,699,701	$86,699,701	$86,699,701	
3	Less: Accumulated Depreciation			($1,572,913)	($1,682,997)	($1,793,080)	($1,903,163)	($2,013,246)	($2,123,329)	($2,233,412)	($2,343,495)	($2,453,578)	($2,563,661)	($2,673,744)	($2,783,827)	($2,893,910)	
4	CWIP - AFUDC-Interest Bearing			0	(0)	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$84,969,073	$85,018,003	$84,906,621	$84,796,538	$84,686,455	$84,576,372	$84,466,289	$84,356,206	$84,246,123	$84,136,040	$84,025,957	$83,915,874	$83,805,791	
6	Average Net Investment				$84,999,472	$84,962,312	$84,851,580	$84,741,497	$84,631,414	$84,521,331	$84,411,248	$84,301,165	$84,191,082	$84,080,999	$83,970,916	$83,860,833	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.97%	1.89%		139,297	139,246	139,065	138,885	138,704	138,523	133,025	132,852	132,678	132,504	132,332	132,158	1,629,269
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		404,128	403,980	403,453	402,930	402,405	401,883	405,907	405,378	404,848	404,319	403,790	403,261	4,846,282
	c. Other (F)				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)				110,084	110,083	110,083	110,083	110,083	110,083	110,083	110,083	110,083	110,083	110,083	110,083	1,320,997
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)				(12,808)	3,792	3,792	3,792	3,792	3,792	3,792	3,792	3,792	3,792	3,792	3,792	28,904
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$640,701	$657,101	$656,393	$655,690	$654,984	$654,281	$652,807	$652,105	$651,401	$650,698	$649,997	$649,294	7,825,452
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$640,701	$657,101	$656,393	$655,690	$654,984	$654,281	$652,807	$652,105	$651,401	$650,698	$649,997	$649,294	7,825,452
10	Energy Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)				0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)				595,115	610,348	609,691	609,038	608,382	607,729	606,360	605,708	605,054	604,401	603,750	603,097	7,268,671
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$595,115	$610,348	$609,691	$609,038	$608,382	$607,729	$606,360	$605,708	$605,054	$604,401	$603,750	$603,097	$7,268,671

Notes:
(A) N/A
(B) Jan - Jun 2020 Line 3 x 7.67% x 1/12. Jul - Dec 2020 Line 3 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.
(C) Depreciation calculated only on assets placed in-service which appear in CAIR Crystal River section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Property taxes calculated only on assets placed in-service which appear in CAIR Crystal River section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2020 - December 2020

Schedule of Amortization and Return
For Project: CAIR/CAMR - Energy (Project 7.4 - Reagents and By-Products)
(in Dollars)

Line	Description	Jan-Jun	Jul-Dec	Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	Working Capital Dr (Cr)																
	a. 0154401 Ammonia Inventory			$542,621	$542,621	$542,621	$540,418	$589,673	$587,967	$633,965	$700,806	$798,632	$893,194	$957,515	$1,085,249	$1,085,249	1,085,249
	b. 0154200 Limestone Inventory (F)			1,193,107	1,196,755	1,196,755	1,193,988	1,158,864	1,041,425	1,046,556	1,145,904	1,171,759	1,217,017	1,245,778	1,309,279	1,565,630	1,565,630
2	Total Working Capital			$1,735,728	1,739,376	1,739,376	1,734,406	1,748,536	1,629,392	1,680,521	1,846,710	1,970,391	2,110,211	2,203,293	2,394,528	2,650,879	2,650,879
3	Average Net Investment				1,737,552	1,739,376	1,736,891	1,741,471	1,688,964	1,654,957	1,763,615	1,908,550	2,040,301	2,156,752	2,298,910	2,522,703	
4	Return on Average Net Working Capital Balance (A)	Jan-Jun	Jul-Dec														
	a. Debt Component (F)	1.97%	1.89%		2,848	2,851	2,847	2,854	2,768	2,712	2,779	3,008	3,215	3,399	3,623	3,976	$36,880
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		8,262	8,270	8,259	8,280	8,031	7,869	8,481	9,178	9,811	10,371	11,055	12,131	109,998
5	Total Return Component (B)				11,110	11,121	11,106	11,134	10,799	10,581	11,260	12,186	13,026	13,770	14,678	16,107	146,878
6	Expense Dr (Cr)																
	a. 502030 Ammonia Expense				0	0	22,715	65,144	130,334	133,126	229,828	242,785	224,296	269,052	38,627	50,999	1,406,904
	b. 502040 Limestone Expense				(3,648)	0	16,800	95,563	330,019	296,876	417,954	450,290	395,088	438,546	88,542	5,010	2,531,041
	c. 502050 Dibasic Acid Expense				0	0	0	0	0	0	21,813	0	0	0	0	0	21,813
	d. 502070 Gypsum Disposal/Sale				(25)	0	(13,121)	(116,191)	(237,620)	(252,571)	(320,992)	(564,551)	(462,902)	183,030	(421,179)	(65,139)	(2,271,262)
	e. 502040 Hydrated Lime Expense				0	0	15,327	68,419	142,498	147,593	258,984	282,598	243,360	310,424	33,779	63,211	1,566,191
	f. 502300 Caustic Expense				0	0	0	0	0	0	0	73,948	73,458	73,327	0	0	220,733
7	Net Expense (C)				(3,673)	0	41,720	112,935	365,231	325,023	607,587	485,069	473,300	1,274,380	(260,233)	54,081	3,475,420
8	Total System Recoverable Expenses (Lines 5 + 7)				$7,437	$11,121	$52,826	$124,069	$376,030	$335,604	$618,847	$497,255	$486,326	$1,288,150	($245,555)	$70,188	$3,622,298
	a. Recoverable Costs Allocated to Energy				7,437	11,121	52,826	124,069	376,030	335,604	618,847	497,255	486,326	1,288,150	(245,555)	70,188	$3,622,298
	b. Recoverable Costs Allocated to Demand				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9	Energy Jurisdictional Factor				0.97570	0.97330	0.94540	0.95410	0.91520	0.91350	0.90640	0.90730	0.92460	0.91720	0.95210	0.92960	
10	Demand Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Retail Energy-Related Recoverable Costs (D)				$7,257	$10,824	$49,942	$118,374	$344,142	$306,574	$560,923	$451,160	$449,657	$1,181,491	($233,792)	$65,247	$3,311,798
12	Retail Demand-Related Recoverable Costs (E)				0	0	0	0	0	0	0	0	0	0	0	0	0
13	Total Jurisdictional Recoverable Costs (Lines 11 + 12)				$7,257	$10,824	$49,942	$118,374	$344,142	$306,574	$560,923	$451,160	$449,657	$1,181,491	($233,792)	$65,247	$3,311,798

Notes:
(A) Jan - Jun 2020 Line 3 x 7.67% x 1/12. Jul - Dec 2020 Line 3 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.
(B) Line 5 is reported on Capital Schedule
(C) Line 7 is reported on O&M Schedule
(D) Line 8a x Line 9
(E) Line 8b x Line 10

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2020 - December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: SEA TURTLE - COASTAL STREET LIGHTING - (Project 9)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$11,324	$11,324	$11,324	$11,324	$11,324	$11,324	$11,324	$11,324	$11,324	$11,324	$11,324	$11,324	$11,324	
3	Less: Accumulated Depreciation			($4,046)	(4,075)	(4,104)	(4,133)	(4,162)	(4,191)	(4,220)	(4,249)	(4,278)	(4,307)	(4,336)	(4,365)	(4,394)	
4	CWIP - Non-Interest Bearing			$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$7,278	$7,249	$7,220	$7,191	$7,162	$7,133	$7,104	$7,075	$7,046	$7,017	$6,988	$6,959	$6,930	
6	Average Net Investment				$7,264	$7,235	$7,206	$7,177	$7,148	$7,119	$7,090	$7,061	$7,032	$7,003	$6,974	$6,945	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.97%	1.89%		12	12	12	12	12	12	11	11	11	11	11	11	138
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		35	34	34	34	34	34	34	34	34	34	34	33	408
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C) 3.0658%				29	29	29	29	29	29	29	29	29	29	29	29	348
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D) 0.7755%				(16)	7	7	7	7	7	7	7	7	7	7	7	61
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$60	$82	$82	$82	$82	$82	$81	$81	$81	$81	$81	$80	955
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$60	$82	$82	$82	$82	$82	$81	$81	$81	$81	$81	$80	955
10	Energy Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - (Distribution)				0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	
12	Retail Energy-Related Recoverable Costs (E)				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)				60	82	82	82	82	82	81	81	81	81	81	80	951
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$60	$82	$82	$82	$82	$82	$81	$81	$81	$81	$81	$80	$951

Notes:
(A) N/A
(B) Jan - Jun 2020 Line 3 x 7.67% x 1/12. Jul - Dec 2020 Line 3 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.
(C) Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2020 - December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: UNDERGROUND STORAGE TANKS - Base (Project 10.1)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$168,941	$168,941	$168,941	$168,941	$168,941	$168,941	$168,941	$168,941	$168,941	$168,941	$168,941	$168,941	$168,941	
3	Less: Accumulated Depreciation			(49,552)	(49,848)	(50,144)	(50,440)	(50,736)	(51,032)	(51,328)	(51,624)	(51,920)	(52,216)	(52,512)	(52,808)	(53,104)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$119,389	$119,093	$118,797	$118,501	$118,205	$117,909	$117,613	$117,317	$117,021	$116,725	$116,429	$116,133	$115,837	
6	Average Net Investment				$119,241	$118,945	$118,649	$118,353	$118,057	$117,761	$117,465	$117,169	$116,873	$116,577	$116,281	$115,985	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.97%	1.89%		195	195	194	194	193	193	185	185	184	184	183	183	2,268
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		567	566	564	563	561	560	565	563	562	561	559	558	6,749
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C) 2.1000%				296	296	296	296	296	296	296	296	296	296	296	296	3,552
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D) 0.8573%				236	121	121	121	121	121	121	121	121	121	121	121	1,567
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$1,294	$1,178	$1,175	$1,174	$1,171	$1,170	$1,167	$1,165	$1,163	$1,162	$1,159	$1,158	14,136
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$1,294	$1,178	$1,175	$1,174	$1,171	$1,170	$1,167	$1,165	$1,163	$1,162	$1,159	$1,158	14,136
10	Energy Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)				0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)				1,202	1,094	1,091	1,090	1,088	1,087	1,084	1,082	1,080	1,079	1,077	1,076	13,130
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$1,202	$1,094	$1,091	$1,090	$1,088	$1,087	$1,084	$1,082	$1,080	$1,079	$1,077	$1,076	$13,130

Notes:
(A) N/A
(B) Jan - Jun 2020 Line 3 x 7.67% x 1/12. Jul - Dec 2020 Line 3 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
January 2020 Property Tax includes an adjustment to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2020 - December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: UNDERGROUND STORAGE TANKS - Intermediate (10.2)
(in Dollars)

Line	Description	Jan-Jun	Jul-Dec	Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$76,006	$76,006	$76,006	$76,006	$76,006	$76,006	$76,006	$76,006	$76,006	$76,006	$76,006	$76,006	$76,006	
3	Less: Accumulated Depreciation			($31,529)	(31,732)	(31,935)	(32,138)	(32,341)	(32,544)	(32,747)	(32,950)	(33,153)	(33,356)	(33,559)	(33,762)	(33,965)	
4	CWIP - Non-Interest Bearing			$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$44,477	$44,274	$44,071	$43,868	$43,665	$43,462	$43,259	$43,056	$42,853	$42,650	$42,447	$42,244	$42,041	
6	Average Net Investment				$44,376	$44,173	$43,970	$43,767	$43,564	$43,361	$43,158	$42,955	$42,752	$42,549	$42,346	$42,143	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.97%	1.89%		73	72	72	72	71	71	68	68	67	67	67	66	834
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		211	210	209	208	207	206	208	207	206	205	204	203	2,484
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C) 3.2000%				203	203	203	203	203	203	203	203	203	203	203	203	2,436
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D) 0.9890%				(40)	63	63	63	63	63	63	63	63	63	63	63	653
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$447	$548	$547	$546	$544	$543	$542	$541	$539	$538	$537	$535	6,407
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$447	$548	$547	$546	$544	$543	$542	$541	$539	$538	$537	$535	6,407
10	Energy Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)				0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
12	Retail Energy-Related Recoverable Costs (E)				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)				325	398	398	397	396	395	394	393	392	391	390	389	4,658
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$325	$398	$398	$397	$396	$395	$394	$393	$392	$391	$390	$389	$4,658

Notes:
(A) N/A
(B) Jan - Jun 2020 Line 3 x 7.67% x 1/12. Jul - Dec 2020 Line 3 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.
(C) Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2020 - December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Effluent Limitation Guidelines CRN - Base (Project 15.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	Investments															
	a. Expenditures/Additions			$31,742	$36,702	$22,532	$90,385	$33,067	$16,401	($47,076)	$204	$0	$626	$1,113	$0	$185,695
	b. Clearings to Plant			0	0	0	0	2,641,712	16,401	(47,076)	204	0	626	1,113	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$0	$0	$0	$0	$0	$2,641,712	$2,658,112	$2,611,036	$2,611,240	$2,611,240	$2,611,866	$2,612,979	$2,612,979	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	(5,438)	(10,909)	(16,283)	(21,658)	(27,033)	(32,409)	(37,787)	
4	CWIP - Non-Interest Bearing		2,427,284	2,459,026	2,495,727	2,518,260	2,608,644	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$2,427,284	$2,459,026	$2,495,727	$2,518,260	$2,608,644	$2,641,711	$2,652,674	$2,600,126	$2,594,957	$2,589,582	$2,584,833	$2,580,570	$2,575,192	
6	Average Net Investment			$2,443,155	$2,477,376	$2,506,993	$2,563,452	$2,625,178	$2,647,193	$2,626,400	$2,597,542	$2,592,269	$2,587,207	$2,582,701	$2,577,881	
7	Return on Average Net Investment (B)	Jan-Jun Jul-Dec														
	a. Debt Component	1.97% 1.89%		4,004	4,060	4,109	4,201	4,302	4,339	4,139	4,094	4,085	4,077	4,070	4,063	49,543
	b. Equity Component Grossed Up For Taxes	5.71% 5.77%		11,617	11,779	11,920	12,189	12,482	12,587	12,630	12,491	12,465	12,441	12,419	12,396	147,416
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	2.4700%		0	0	0	0	0	5,438	5,471	5,374	5,375	5,375	5,376	5,378	37,787
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.0525%		0	0	0	0	0	116	116	114	114	114	114	114	802
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$15,621	$15,839	$16,029	$16,390	$16,784	$22,480	$22,356	$22,073	$22,039	$22,007	$21,979	$21,951	235,548
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$15,621	$15,839	$16,029	$16,390	$16,784	$22,480	$22,356	$22,073	$22,039	$22,007	$21,979	$21,951	235,548
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)			14,510	14,712	14,889	15,224	15,590	20,881	20,765	20,503	20,471	20,441	20,415	20,389	218,789
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$14,510	$14,712	$14,889	$15,224	$15,590	$20,881	$20,765	$20,503	$20,471	$20,441	$20,415	$20,389	$218,789

Notes:
(A) N/A
(B) Jan - Jun 2020 Line 3 x 7.67% x 1/12. Jul - Dec 2020 Line 3 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2020 - December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: NPDES - Intermediate (Project 16)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$12,841,870	$12,841,870	$12,841,870	$12,841,870	$12,841,870	$12,841,870	$12,841,870	$12,841,870	$12,841,870	$12,841,870	$12,841,870	$12,841,870	$12,841,870	
3	Less: Accumulated Depreciation			($2,144,574)	(2,180,246)	(2,215,918)	(2,251,590)	(2,287,262)	(2,322,934)	(2,358,606)	(2,394,278)	(2,429,950)	(2,465,622)	(2,501,294)	(2,536,966)	(2,572,638)	
4	CWIP - Non-Interest Bearing			$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$10,697,296	$10,661,624	$10,625,952	$10,590,280	$10,554,608	$10,518,936	$10,483,264	$10,447,592	$10,411,920	$10,376,248	$10,340,576	$10,304,904	$10,269,232	
6	Average Net Investment				$10,679,460	$10,643,788	$10,608,116	$10,572,444	$10,536,772	$10,501,100	$10,465,428	$10,429,756	$10,394,084	$10,358,412	$10,322,740	$10,287,068	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.97%	1.89%		17,503	17,444	17,386	17,327	17,269	17,210	16,493	16,436	16,380	16,324	16,268	16,212	202,252
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		50,779	50,609	50,440	50,270	50,100	49,931	50,325	50,153	49,982	49,810	49,639	49,467	601,505
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)	3.3333%			35,672	35,672	35,672	35,672	35,672	35,672	35,672	35,672	35,672	35,672	35,672	35,672	428,064
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.8150%			(9,561)	8,722	8,722	8,722	8,722	8,722	8,722	8,722	8,722	8,722	8,722	8,722	86,381
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$94,393	$112,447	$112,220	$111,991	$111,763	$111,535	$111,212	$110,983	$110,756	$110,528	$110,301	$110,073	1,318,202
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$94,393	$112,447	$112,220	$111,991	$111,763	$111,535	$111,212	$110,983	$110,756	$110,528	$110,301	$110,073	1,318,202
10	Energy Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)				0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
12	Retail Energy-Related Recoverable Costs (E)				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)				68,627	81,752	81,587	81,421	81,255	81,089	80,854	80,688	80,523	80,357	80,192	80,026	958,373
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$68,627	$81,752	$81,587	$81,421	$81,255	$81,089	$80,854	$80,688	$80,523	$80,357	$80,192	$80,026	$958,373

Notes:
(A) N/A
(B) Jan - Jun 2020 Line 3 x 7.67% x 1/12. Jul - Dec 2020 Line 3 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2020 - December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: MERCURY & AIR TOXIC STANDARDS (MATS) - CRYSTAL RIVER UNITS 4 & 5 - Energy (Project 17)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$3,690,187	$3,690,187	$3,690,187	$3,690,187	$3,690,187	$3,690,187	$3,690,187	$3,690,187	$3,690,187	$3,690,187	$3,690,187	$3,690,187	$3,690,187	
3	Less: Accumulated Depreciation			($345,965)	(352,547)	(359,129)	(365,711)	(372,293)	(378,875)	(385,457)	(392,039)	(398,621)	(405,203)	(411,785)	(418,367)	(424,949)	
4	CWIP - Non-Interest Bearing			$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$3,344,222	$3,337,640	$3,331,058	$3,324,476	$3,317,894	$3,311,312	$3,304,730	$3,298,148	$3,291,566	$3,284,984	$3,278,402	$3,271,820	$3,265,238	
6	Average Net Investment				$3,340,931	$3,334,349	$3,327,767	$3,321,185	$3,314,603	$3,308,021	$3,301,439	$3,294,857	$3,288,275	$3,281,693	$3,275,111	$3,268,529	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.97%	1.89%		5,476	5,465	5,454	5,443	5,432	5,422	5,203	5,192	5,182	5,172	5,161	5,151	63,753
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		15,885	15,854	15,823	15,792	15,760	15,729	15,876	15,844	15,812	15,781	15,749	15,757	189,662
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C) Blended				6,582	6,582	6,582	6,582	6,582	6,582	6,582	6,582	6,582	6,582	6,582	6,582	78,984
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D) 0.0525%				(1,577)	161	161	161	161	161	161	161	161	161	161	161	194
	e. Other (E)				(597)	(597)	(597)	(597)	(597)	(597)	(597)	(597)	(597)	(597)	(597)	(597)	(7,160)
9	Total System Recoverable Expenses (Lines 7 + 8)				$25,770	$27,465	$27,423	$27,381	$27,338	$27,297	$27,225	$27,182	$27,140	$27,099	$27,056	$27,054	325,433
	a. Recoverable Costs Allocated to Energy				25,770	27,465	27,423	27,381	27,338	27,297	27,225	27,182	27,140	27,099	27,056	27,054	325,433
	b. Recoverable Costs Allocated to Demand				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
10	Energy Jurisdictional Factor				0.97570	0.97330	0.94540	0.95410	0.91520	0.91350	0.90640	0.90730	0.92460	0.91720	0.95210	0.92960	
11	Demand Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
12	Retail Energy-Related Recoverable Costs (F)				$25,143	$26,732	$25,926	$26,125	$25,020	$24,936	$24,677	$24,663	$25,094	$24,856	$25,760	$25,150	304,081
13	Retail Demand-Related Recoverable Costs (G)				0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$25,143	$26,732	$25,926	$26,125	$25,020	$24,936	$24,677	$24,663	$25,094	$24,856	$25,760	$25,150	$304,081

Notes:
(A) N/A
(B) Jan - Jun 2020 Line 3 x 7.67% x 1/12. Jul - Dec 2020 Line 3 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.
(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 19990007-EI, Order No. PSC-1999-2513-FOF-EI.
(F) Line 9a x Line 10
(G) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2020 - December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: MERCURY & AIR TOXIC STANDARDS (MATS) - ANCLOTE GAS CONVERSION - Energy (Project 17.1)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other - AFUDC (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$133,918,267	$133,918,267	$133,918,267	$133,918,267	$133,918,267	$133,918,267	$133,918,267	$133,918,267	$133,918,267	$133,918,267	$133,918,267	$133,918,267	$133,918,267	
3	Less: Accumulated Depreciation			($17,457,598)	(17,700,012)	(17,942,426)	(18,184,840)	(18,427,254)	(18,669,668)	(18,912,082)	(19,154,496)	(19,396,910)	(19,639,324)	(19,881,738)	(20,124,152)	(20,366,566)	
4	CWIP - AFUDC Bearing			$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$116,460,669	$116,218,255	$115,975,841	$115,733,427	$115,491,013	$115,248,599	$115,006,185	$114,763,771	$114,521,357	$114,278,943	$114,036,529	$113,794,115	$113,551,701	
6	Average Net Investment				$116,339,462	$116,097,048	$115,854,634	$115,612,220	$115,369,806	$115,127,392	$114,884,978	$114,642,564	$114,400,150	$114,157,736	$113,915,322	$113,672,908	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.97%	1.89%		190,671	190,273	189,876	189,479	189,081	188,684	181,049	180,667	180,285	179,903	179,521	179,139	2,218,628
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		553,172	552,019	550,866	549,714	548,561	547,409	552,446	551,280	550,114	548,949	547,783	546,617	6,598,930
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C) 2.1722%				242,414	242,414	242,414	242,414	242,414	242,414	242,414	242,414	242,414	242,414	242,414	242,414	2,908,968
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D) 0.6390%				(211,077)	71,311	71,311	71,311	71,311	71,311	71,311	71,311	71,311	71,311	71,311	71,311	573,344
	e. Other (E)				(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(177,534)
9	Total System Recoverable Expenses (Lines 7 + 8)				$760,385	$1,041,223	$1,039,673	$1,038,124	$1,036,573	$1,035,024	$1,032,426	$1,030,878	$1,029,330	$1,027,783	$1,026,235	$1,024,687	12,122,336
	a. Recoverable Costs Allocated to Energy				760,385	1,041,223	1,039,673	1,038,124	1,036,573	1,035,024	1,032,426	1,030,878	1,029,330	1,027,783	1,026,235	1,024,687	12,122,336
	b. Recoverable Costs Allocated to Demand				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
10	Energy Jurisdictional Factor				0.97570	0.97330	0.94540	0.95410	0.91520	0.91350	0.90640	0.90730	0.92460	0.91720	0.95210	0.92960	
11	Demand Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
12	Retail Energy-Related Recoverable Costs (F)				$741,908	$1,013,422	$982,906	$990,474	$948,671	$945,494	$935,790	$935,315	$951,718	$942,682	$977,078	$952,549	11,318,007
13	Retail Demand-Related Recoverable Costs (G)				0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$741,908	$1,013,422	$982,906	$990,474	$948,671	$945,494	$935,790	$935,315	$951,718	$942,682	$977,078	$952,549	$11,318,007

Notes:
(A) N/A
(B) Jan - Jun 2020 Line 3 x 7.67% x 1/12. Jul - Dec 2020 Line 3 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.
(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 19990007-EI, Order No. PSC-1999-2513-FOF-EI.
(F) Line 9a x Line 10
(G) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2020 - December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: MERCURY & AIR TOXIC STANDARDS (MATS) - CRYSTAL RIVER UNITS 1 & 2 - Energy (Project 17.2)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	22,681,074	
	d. Other - AFUDC (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$22,681,074	$22,681,074	$22,681,074	$22,681,074	$22,681,074	$22,681,074	$22,681,074	$22,681,074	$22,681,074	$22,681,074	$22,681,074	$22,681,074	$0	
3	Less: Accumulated Depreciation			($3,846,177)	(3,916,110)	(3,986,043)	(4,055,977)	(4,125,910)	(4,195,843)	(4,265,777)	(4,335,710)	(4,405,643)	(4,475,577)	(4,545,510)	(4,615,443)	0	
4	CWIP - Non-Interest Bearing			$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$18,834,897	$18,764,964	$18,695,030	$18,625,097	$18,555,164	$18,485,230	$18,415,297	$18,345,364	$18,275,430	$18,205,497	$18,135,564	$18,065,630	$0	
6	Average Net Investment				$18,799,930	$18,729,997	$18,660,064	$18,590,130	$18,520,197	$18,450,264	$18,380,330	$18,310,397	$18,240,464	$18,170,530	$18,100,597	$9,032,815	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.97%	1.89%		30,812	30,697	30,582	30,468	30,353	30,238	28,966	28,856	28,745	28,635	28,525	14,235	341,112
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		89,390	89,058	88,725	88,392	88,060	87,727	88,385	88,049	87,713	87,376	87,040	43,220	1,013,135
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C) 3.7000%				69,933	69,933	69,933	69,933	69,933	69,933	69,933	69,933	69,933	69,933	69,933	69,933	839,200
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D) 0.0525%				(9,619)	992	992	992	992	992	992	992	992	992	992	992	1,293
	e. Other (E)				(10,540)	(10,540)	(10,540)	(10,540)	(10,540)	(10,540)	(10,540)	(10,540)	(10,540)	(10,540)	(10,540)	(10,540)	(126,475)
9	Total System Recoverable Expenses (Lines 7 + 8)				$169,977	$180,141	$179,693	$179,246	$178,799	$178,351	$177,737	$177,291	$176,844	$176,397	$175,951	$117,841	2,068,264
	a. Recoverable Costs Allocated to Energy				169,977	180,141	179,693	179,246	178,799	178,351	177,737	177,291	176,844	176,397	175,951	117,841	2,068,264
	b. Recoverable Costs Allocated to Demand				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
10	Energy Jurisdictional Factor				0.97570	0.97330	0.94540	0.95410	0.91520	0.91350	0.90640	0.90730	0.92460	0.91720	0.95210	0.92960	
11	Demand Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
12	Retail Energy-Related Recoverable Costs (F)				$165,846	$175,331	$169,881	$171,018	$163,637	$162,923	$161,101	$160,856	$163,510	$161,791	$167,523	$109,545	1,932,961
13	Retail Demand-Related Recoverable Costs (G)				0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$165,846	$175,331	$169,881	$171,018	$163,637	$162,923	$161,101	$160,856	$163,510	$161,791	$167,523	$109,545	$1,932,961

Notes:
(A) N/A
(B) Jan - Jun 2020 Line 3 x 7.67% x 1/12. Jul - Dec 2020 Line 3 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.
(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 19990007-EI, Order No. PSC-1999-2513-FOF-EI.
(F) Line 9a x Line 10
(G) Line 9b x Line 11

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2020 - December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: COAL COMBUSTION RESIDUAL (CCR) RULE - Base (Project 18)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$80,093	$43,485	$38,283	$209,236	$888,403	$839,732	$2,099,232
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$446,090	446,090	446,090	446,090	446,090	446,090	446,090	446,090	446,090	446,090	446,090	446,090	446,090	
3	Less: Accumulated Depreciation			(20,252)	(21,058)	(21,865)	(22,671)	(23,478)	(24,284)	(25,091)	(25,896)	(26,702)	(27,507)	(28,313)	(29,118)	(29,288)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	80,093	123,578	161,861	371,097	1,259,500	2,099,232	
5	Net Investment (Lines 2 + 3 + 4)			$425,838	$425,032	$424,225	$423,419	$422,612	$421,806	$420,999	$500,286	$542,966	$580,444	$788,874	$1,676,471	$2,516,034	
6	Average Net Investment				$425,435	$424,628	$423,822	$423,015	$422,209	$421,402	$460,643	$521,626	$561,705	$684,659	$1,232,673	$2,096,253	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.97%	1.89%		697	696	695	693	692	691	726	822	885	1,079	1,943	3,314	12,933
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		2,023	2,019	2,015	2,011	2,008	2,004	2,215	2,508	2,701	3,292	5,928	10,080	38,804
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C) 2.1695%				806	806	806	806	806	806	806	806	806	806	806	806	9,672
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D) 0.0525%				(142)	20	20	20	20	20	20	20	20	20	20	20	78
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$3,385	$3,541	$3,536	$3,530	$3,526	$3,521	$3,767	$4,156	$4,412	$5,197	$8,697	$14,220	61,487
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$3,385	$3,541	$3,536	$3,530	$3,526	$3,521	$3,767	$4,156	$4,412	$5,197	$8,697	$14,220	61,488
10	Energy Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor				0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)				3,144	3,289	3,284	3,279	3,275	3,270	3,499	3,860	4,098	4,827	8,078	13,208	57,113
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$3,144	$3,289	$3,284	$3,279	$3,275	$3,270	$3,499	$3,860	$4,098	$4,827	$8,078	$13,208	$57,113

Notes:
(A) N/A
(B) Jan - Jun 2020 Line 3 x 7.67% x 1/12. Jul - Dec 2020 Line 3 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2020 - December 2020

Capital Structure and Cost Rates

Class of Capital	Retail	Amount	Ratio	Cost Rate	Weighted Cost Rate	PreTax Weighted Cost Rate
CE		$4,874,577,393	41.01%	0.10500	4.31%	5.71%
PS		-	0.00%	0.00000	0.00%	0.00%
LTD		4,845,025,196	40.77%	0.04701	1.92%	1.92%
STD		(59,426,995)	-0.50%	-0.00358	0.00%	0.00%
CD-Active		176,756,874	1.49%	0.02378	0.04%	0.04%
CD-Inactive		1,853,499	0.02%	0.00000	0.00%	0.00%
ADIT		2,026,313,275	17.05%	0.00000	0.00%	0.00%
FAS 109		-	0.00%	0.00000	0.00%	0.00%
ITC		19,805,922	0.17%	0.07715	0.01%	0.01%
Total	$	11,884,905,162	100.00%		6.27%	7.67%
				Total Debt	1.97%	1.97%
				Total Equity	4.31%	5.71%

May 2019 DEF Surveillance Report capital structure and cost rates. See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU, Docket 120007-EI.

The May 2019 DEF Survaillance Report reflects the tax reform adjustments set forth in Paragraph 16 of DEF's 2017 Settlement.

Class of Capital	Retail	Amount	Ratio	Cost Rate	Weighted Cost Rate	PreTax Weighted Cost Rate
CE	$	5,587,139,333	41.48%	0.10500	4.36%	5.77%
PS		-	0.00%	0.00000	0.00%	0.00%
LTD		5,219,534,862	38.75%	0.04616	1.79%	1.79%
STD		228,721,050	1.70%	0.02101	0.04%	0.04%
CD-Active		184,176,907	1.37%	0.02434	0.03%	0.03%
CD-Inactive		1,820,718	0.01%	0.00000	0.00%	0.00%
ADIT		2,189,708,749	16.26%	0.00000	0.00%	0.00%
FAS 109		-	0.00%	0.00000	0.00%	0.00%
ITC		58,310,573	0.43%	0.07658	0.03%	0.03%
Total		$13,469,412,193	100.00%		6.25%	7.66%
				Total Debt	1.89%	1.89%
				Total Equity	4.36%	5.77%

May 2020 DEF Surveillance Report capital structure and cost rates. See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU, Docket 120007-EI.

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Capital Program Detail

January 2020 - December 2020
Final True-Up
Docket No. 20210007-EI

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BARTOW CTs (Project 4.1b)
(in Dollars)

Line	Description	Jan-Jun	Jul-Dec	Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$1,473,801	$1,473,801	$1,473,801	$1,473,801	$1,473,801	$1,473,801	$1,473,801	$1,473,801	$1,473,801	$1,473,801	$1,473,801	$1,473,801	$1,473,801	
3	Less: Accumulated Depreciation			(469,383)	(473,068)	(476,753)	(480,438)	(484,123)	(487,808)	(491,493)	(495,178)	(498,863)	(502,548)	(506,233)	(509,918)	(513,597)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$1,004,418	$1,000,733	$997,048	$993,363	$989,678	$985,993	$982,308	$978,623	$974,938	$971,253	$967,568	$963,883	$960,204	
6	Average Net Investment				1,002,576	998,891	995,206	991,521	987,836	984,151	980,466	976,781	973,096	969,411	965,726	962,044	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.97%	1.89%		1,643	1,637	1,631	1,625	1,619	1,613	1,545	1,539	1,534	1,528	1,522	1,516	18,952
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		4,767	4,750	4,732	4,714	4,697	4,679	4,715	4,697	4,679	4,662	4,644	4,626	56,362
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation 3.0000%				3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	44,220
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B) 0.00815				(1,425)	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	9,586
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$8,670	$11,073	$11,049	$11,025	$11,002	$10,978	$10,946	$10,922	$10,899	$10,876	$10,852	$10,828	$129,120
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$8,670	$11,073	$11,049	$11,025	$11,002	$10,978	$10,946	$10,922	$10,899	$10,876	$10,852	$10,828	$129,120

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - INTERCESSION CITY CTs (Project 4.1c)
(in Dollars)

Line	Description	Jan-Jun	Jul-Dec	Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$1,661,664	$1,661,664	$1,661,664	$1,661,664	$1,661,664	$1,661,664	$1,661,664	$1,661,664	$1,661,664	$1,661,664	$1,661,664	$1,661,664	$1,661,664	
3	Less: Accumulated Depreciation			(1,272,803)	(1,281,942)	(1,291,081)	(1,300,220)	(1,309,359)	(1,318,498)	(1,327,637)	(1,336,776)	(1,345,915)	(1,355,054)	(1,364,193)	(1,373,332)	(1,382,471)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$388,861	$379,722	$370,583	$361,444	$352,305	$343,166	$334,027	$324,888	$315,749	$306,610	$297,471	$288,332	$279,193	
6	Average Net Investment				384,292	375,153	366,014	356,875	347,736	338,597	329,458	320,319	311,180	302,041	292,902	283,763	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.97%	1.89%		630	615	600	585	570	555	519	505	490	476	462	447	6,454
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		1,827	1,784	1,740	1,697	1,653	1,610	1,584	1,540	1,496	1,452	1,408	1,365	19,156
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation 6.6000%				9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	109,668
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B) 0.007220				(1,426)	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	9,574
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$10,170	$12,538	$12,479	$12,421	$12,362	$12,304	$12,242	$12,184	$12,125	$12,067	$12,009	$11,951	$144,852
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$10,170	$12,538	$12,479	$12,421	$12,362	$12,304	$12,242	$12,184	$12,125	$12,067	$12,009	$11,951	$144,852

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.
(B) January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - AVON PARK CTs (Project 4.1d)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant					0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements					0	0	0	0	0	0	0	0	0	178,938	0	0	
	d. Other					0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base				$178,938	$178,938	$178,938	$178,938	$178,938	$178,938	$178,938	$178,938	$178,938	$178,938	$0	$0	$0	
3	Less: Accumulated Depreciation				(107,081)	(107,797)	(108,513)	(109,229)	(109,945)	(110,661)	(111,377)	(112,093)	(112,809)	(113,525)	64,697	0	0	
3a	Regulatory Asset Balance (C)				0	0	0	0	0	0	0	0	0	0	0	59,306	53,914	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$71,857	$71,141	$70,425	$69,709	$68,993	$68,277	$67,561	$66,845	$66,129	$65,413	$64,697	$59,306	$53,914	
6	Average Net Investment					71,499	70,783	70,067	69,351	68,635	67,919	67,203	66,487	65,771	65,055	62,002	56,610	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		1.97%	1.89%		117	116	115	114	112	111	106	105	104	103	98	89	1,290
	b. Equity Component Grossed Up For Taxes		5.71%	5.77%		340	337	333	330	326	323	323	320	316	313	298	272	3,831
	c. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																	
	a. Depreciation	4.8000%				716	716	716	716	716	716	716	716	716	716	0	0	7,160
	b. Amortization (C)					0	0	0	0	0	0	0	0	0	0	5,391	5,391	10,783
	c. Dismantlement					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B)	0.008000				(2,307)	119	119	119	119	119	119	119	119	119	0	0	(1,236)
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					($1,134)	$1,288	$1,283	$1,279	$1,273	$1,269	$1,264	$1,260	$1,255	$1,251	$5,787	$5,752	$21,828
	a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand					($1,134)	$1,288	$1,283	$1,279	$1,273	$1,269	$1,264	$1,260	$1,255	$1,251	$5,787	$5,752	$21,828

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BAYBORO CTs (Project 4.1e)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant					0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements					0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other					0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base				$730,295	$730,295	$730,295	$730,295	$730,295	$730,295	$730,295	$730,295	$730,295	$730,295	$730,295	$730,295	$730,295	
3	Less: Accumulated Depreciation				(264,349)	(266,171)	(267,993)	(269,815)	(271,637)	(273,459)	(275,280)	(277,102)	(278,924)	(280,746)	(282,568)	(284,390)	(286,217)	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$465,946	$464,124	$462,302	$460,480	$458,659	$456,837	$455,015	$453,193	$451,371	$449,549	$447,728	$445,906	$444,079	
6	Average Net Investment					465,035	463,213	461,391	459,570	457,748	455,926	454,104	452,282	450,460	448,638	446,817	444,992	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		1.97%	1.89%		762	759	756	753	750	747	716	713	710	707	704	701	8,778
	b. Equity Component Grossed Up For Taxes		5.71%	5.77%		2,211	2,202	2,194	2,185	2,177	2,168	2,184	2,175	2,166	2,157	2,149	2,140	26,108
	c. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																	
	a. Depreciation	2.9936%				1,822	1,822	1,822	1,822	1,822	1,822	1,822	1,822	1,822	1,822	1,822	1,822	21,862
	b. Amortization					0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B)	0.011030				(1,755)	671	671	671	671	671	671	671	671	671	671	671	5,629
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					$3,040	$5,454	$5,443	$5,431	$5,420	$5,408	$5,393	$5,381	$5,369	$5,357	$5,346	$5,334	$62,377
	a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand					$3,040	$5,454	$5,443	$5,431	$5,420	$5,408	$5,393	$5,381	$5,369	$5,357	$5,346	$5,334	$62,377

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.
(B) January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.
(C) Investment amortized over one year as approved in Order No. PSC-2019-0500-FOF-EI.

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - SUWANNEE CTs (Project 4.1f)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant					0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements					0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other					0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base				$1,037,199	$1,037,199	$1,037,199	$1,037,199	$1,037,199	$1,037,199	$1,037,199	$1,037,199	$1,037,199	$1,037,199	$1,037,199	$1,037,199	$1,037,199	
3	Less: Accumulated Depreciation				(426,600)	(429,452)	(432,304)	(435,156)	(438,008)	(440,860)	(443,712)	(446,564)	(449,416)	(452,268)	(455,120)	(457,972)	(460,824)	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$610,599	$607,747	$604,895	$602,043	$599,191	$596,339	$593,487	$590,635	$587,783	$584,931	$582,079	$579,227	$576,375	
6	Average Net Investment					609,173	606,321	603,469	600,617	597,765	594,913	592,061	589,209	586,357	583,505	580,653	577,801	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		1.97%	1.89%		998	994	989	984	980	975	933	929	924	920	915	911	11,452
	b. Equity Component Grossed Up For Taxes		5.71%	5.77%		2,897	2,883	2,869	2,856	2,842	2,829	2,847	2,833	2,820	2,806	2,792	2,778	34,052
	c. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																	
	a. Depreciation	3.3000%				2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	34,224
	b. Amortization					0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B)	0.008390				(1,701)	725	725	725	725	725	725	725	725	725	725	725	6,274
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					$5,046	$7,454	$7,435	$7,417	$7,399	$7,381	$7,357	$7,339	$7,321	$7,303	$7,284	$7,266	$86,002
	a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand					$5,046	$7,454	$7,435	$7,417	$7,399	$7,381	$7,357	$7,339	$7,321	$7,303	$7,284	$7,266	$86,002

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - DeBARY CTs (Project 4.1g)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant					0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements					0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other					0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base				$3,616,904	$3,616,904	$3,616,904	$3,616,904	$3,616,904	$3,616,904	$3,616,904	$3,616,904	$3,616,904	$3,616,904	$3,616,904	$3,616,904	$3,616,904	
3	Less: Accumulated Depreciation				(916,094)	(923,931)	(931,768)	(939,605)	(947,442)	(955,279)	(963,116)	(970,953)	(978,790)	(986,627)	(994,464)	(1,002,301)	(1,010,126)	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$2,700,810	$2,692,973	$2,685,136	$2,677,299	$2,669,462	$2,661,625	$2,653,788	$2,645,951	$2,638,114	$2,630,277	$2,622,440	$2,614,603	$2,606,778	
6	Average Net Investment					2,696,891	2,689,054	2,681,217	2,673,380	2,665,543	2,657,706	2,649,869	2,642,032	2,634,195	2,626,358	2,618,521	2,610,690	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		1.97%	1.89%		4,420	4,407	4,394	4,381	4,369	4,356	4,176	4,164	4,151	4,139	4,127	4,114	51,198
	b. Equity Component Grossed Up For Taxes		5.71%	5.77%		12,823	12,786	12,749	12,711	12,674	12,637	12,742	12,705	12,667	12,629	12,592	12,554	152,269
	c. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																	
	a. Depreciation	2.6000%				$7,837	$7,837	$7,837	$7,837	$7,837	$7,837	$7,837	$7,837	$7,837	$7,837	$7,837	$7,837	94,044
	b. Amortization					0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B)	0.008220				52	2,478	2,478	2,478	2,478	2,478	2,478	2,478	2,478	2,478	2,478	2,478	27,310
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					$25,132	$27,508	$27,458	$27,407	$27,358	$27,308	$27,233	$27,184	$27,133	$27,083	$27,034	$26,983	$324,821
	a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand					$25,132	$27,508	$27,458	$27,407	$27,358	$27,308	$27,233	$27,184	$27,133	$27,083	$27,034	$26,983	$324,821

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.
(B) January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - University of Florida (Project 4.1h)
(in Dollars)

Line Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1 Investments																
a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base			$141,435	$141,435	$141,435	$141,435	$141,435	$141,435	$141,435	$141,435	$141,435	$141,435	$141,435	$141,435	$141,435	
3 Less: Accumulated Depreciation			(66,126)	(66,367)	(66,608)	(66,849)	(67,090)	(67,331)	(67,572)	(67,813)	(68,054)	(68,295)	(68,536)	(68,777)	(69,018)	
4 CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)			$75,309	$75,068	$74,827	$74,586	$74,345	$74,104	$73,863	$73,622	$73,381	$73,140	$72,899	$72,658	$72,417	
6 Average Net Investment				75,188	74,947	74,706	74,465	74,224	73,983	73,742	73,501	73,260	73,019	72,778	72,537	
7 Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
a. Debt Component	1.97%	1.89%		123	123	122	122	122	121	116	116	115	115	115	114	1,424
b. Equity Component Grossed Up For Taxes	5.71%	5.77%		358	356	355	354	353	352	355	353	352	351	350	349	4,238
c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses																
a. Depreciation 2.0482%				241	241	241	241	241	241	241	241	241	241	241	241	2,892
b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes (B) 0.009910				(2,309)	117	117	117	117	117	117	117	117	117	117	117	(1,022)
e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)				($1,587)	$837	$835	$834	$833	$831	$829	$827	$825	$824	$823	$821	$7,532
a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand				($1,587)	$837	$835	$834	$833	$831	$829	$827	$825	$824	$823	$821	$7,532

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Higgins (Project 4.1i)
(in Dollars)

Line Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1 Investments																
a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3 Less: Accumulated Depreciation			0	0	0	0	0	0	0	0	0	0	0	0	0	
3a Regulatory Asset Balance (C)			169,932	155,771	141,610	127,449	113,288	99,127	84,966	70,805	56,644	42,483	28,322	14,161	0	
4 CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)			$169,932	$155,771	$141,610	$127,449	$113,288	$99,127	$84,966	$70,805	$56,644	$42,483	$28,322	$14,161	$0	
6 Average Net Investment				162,851	148,690	134,529	120,368	106,207	92,046	77,885	63,724	49,563	35,402	21,241	7,080	
7 Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
a. Debt Component	1.97%	1.89%		267	244	220	197	174	151	123	100	78	56	33	11	1,654
b. Equity Component Grossed Up For Taxes	5.71%	5.77%		774	707	640	572	505	438	375	306	238	170	102	34	4,861
c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses																
a. Depreciation 5.4000%				0	0	0	0	0	0	0	0	0	0	0	0	0
b. Amortization (C)				14,161	14,161	14,161	14,161	14,161	14,161	14,161	14,161	14,161	14,161	14,161	14,161	169,932
c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes (B) 0.008270				0	0	0	0	0	0	0	0	0	0	0	0	0
e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)				$15,202	$15,112	$15,021	$14,930	$14,840	$14,750	$14,659	$14,567	$14,477	$14,387	$14,296	$14,206	$176,447
a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand				$15,202	$15,112	$15,021	$14,930	$14,840	$14,750	$14,659	$14,567	$14,477	$14,387	$14,296	$14,206	$176,447

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.
(B) January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.
(C) Investment amortized over one year as approved in Order No. PSC-2019-0500-FOF-EI.

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 1 & 2 (Project 4.2)
(in Dollars)

Line Description				Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1 Investments																	
a. Expenditures/Additions					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant					0	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements					0	0	0	0	0	0	0	0	0	0	0	33,092	
d. Other					0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base				$33,092	$33,092	$33,092	$33,092	$33,092	$33,092	$33,092	$33,092	$33,092	$33,092	$33,092	$33,092	$0	
3 Less: Accumulated Depreciation				(20,787)	(20,889)	(20,991)	(21,093)	(21,195)	(21,297)	(21,399)	(21,501)	(21,603)	(21,705)	(21,807)	(21,909)	0	
4 CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)				$12,305	$12,203	$12,101	$11,999	$11,897	$11,795	$11,693	$11,591	$11,489	$11,387	$11,285	$11,183	$0	
6 Average Net Investment					12,254	12,152	12,050	11,948	11,846	11,744	11,642	11,540	11,438	11,336	11,234	5,592	
7 Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
a. Debt Component		1.97%	1.89%		20	20	20	20	19	19	18	18	18	18	18	9	217
b. Equity Component Grossed Up For Taxes		5.71%	5.77%		58	58	57	57	56	56	56	55	55	55	54	27	644
c. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses																	
a. Depreciation	3.7000%				102	102	102	102	102	102	102	102	102	102	102	102	1,224
b. Amortization					0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes (B)	0.001645				5	5	5	5	5	5	5	5	5	5	5	5	60
e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)					$185	$185	$184	$184	$182	$182	$181	$180	$180	$180	$179	$143	$2,145
a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand					$185	$185	$184	$184	$182	$182	$181	$180	$180	$180	$179	$143	$2,145

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 4 & 5 (Project 4.2a)
(in Dollars)

Line Description				Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1 Investments																	
a. Expenditures/Additions					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant					0	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements					0	0	0	0	0	0	0	0	0	0	0	0	
d. Other					0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base				$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	
3 Less: Accumulated Depreciation				(24,748)	(27,678)	(30,608)	(33,538)	(36,468)	(39,398)	(42,328)	(45,258)	(48,188)	(51,118)	(54,048)	(56,978)	(59,908)	
4 CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)				$2,341,199	$2,338,269	$2,335,339	$2,332,409	$2,329,479	$2,326,549	$2,323,619	$2,320,689	$2,317,759	$2,314,829	$2,311,899	$2,308,969	$2,306,039	
6 Average Net Investment					2,339,734	2,336,804	2,333,874	2,330,944	2,328,014	2,325,084	2,322,154	2,319,224	2,316,294	2,313,364	2,310,434	2,307,504	
7 Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
a. Debt Component		1.97%	1.89%		3,835	3,830	3,825	3,820	3,815	3,811	3,660	3,655	3,650	3,646	3,641	3,636	44,824
b. Equity Component Grossed Up For Taxes		5.71%	5.77%		11,125	11,111	11,097	11,083	11,069	11,055	11,167	11,152	11,138	11,124	11,110	11,096	133,327
c. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses																	
a. Depreciation	1.4860%				2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	35,160
b. Amortization					0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes (B)	0.001645				(389)	324	324	324	324	324	324	324	324	324	324	324	3,175
e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)					$17,501	$18,195	$18,176	$18,157	$18,138	$18,120	$18,081	$18,061	$18,042	$18,024	$18,005	$17,986	$216,486
a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand					$17,501	$18,195	$18,176	$18,157	$18,138	$18,120	$18,081	$18,061	$18,042	$18,024	$18,005	$17,986	$216,486

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.
(B) January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Anclote (Project 4.3)
(in Dollars)

Line Description	Rate	Jan-Jun	Jul-Dec	Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1 Investments																	
a. Expenditures/Additions					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant					0	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements					0	0	0	0	0	0	0	0	0	0	0	0	
d. Other					0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base				$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	
3 Less: Accumulated Depreciation				(85,386)	(85,911)	(86,436)	(86,961)	(87,486)	(88,011)	(88,536)	(89,061)	(89,586)	(90,111)	(90,636)	(91,161)	(91,686)	
4 CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)				$204,911	$204,386	$203,861	$203,336	$202,811	$202,286	$201,761	$201,236	$200,711	$200,186	$199,661	$199,136	$198,611	
6 Average Net Investment					204,649	204,124	203,599	203,074	202,549	202,024	201,499	200,974	200,449	199,924	199,399	198,874	
7 Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
a. Debt Component		1.97%	1.89%		335	335	334	333	332	331	318	317	316	315	314	313	3,893
b. Equity Component Grossed Up For Taxes		5.71%	5.77%		973	971	968	966	963	961	969	966	964	961	959	956	11,577
c. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses																	
a. Depreciation	2.1722%				525	525	525	525	525	525	525	525	525	525	525	525	6,300
b. Amortization					0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes (B)	0.006390				(434)	155	155	155	155	155	155	155	155	155	155	155	1,271
e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)					$1,399	$1,986	$1,982	$1,979	$1,975	$1,972	$1,967	$1,963	$1,960	$1,956	$1,953	$1,949	$23,041
a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand					$1,399	$1,986	$1,982	$1,979	$1,975	$1,972	$1,967	$1,963	$1,960	$1,956	$1,953	$1,949	$23,041

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.
(B) January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2019 through December 2019
CAIR CTs (Project 7.2 Recap)

For Project: CAIR CTs - AVON PARK (Project 7.2a)
(in Dollars)

Line	Description	Rate	Jan-Jun	Jul-Dec	Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant					0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements					0	0	0	0	0	0	0	0	0	161,754	0	0	
	d. Other					0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base				$161,754	$161,754	$161,754	$161,754	$161,754	$161,754	$161,754	$161,754	$161,754	$161,754	$0	$0	$0	
3	Less: Accumulated Depreciation				(53,033)	(53,437)	(53,841)	(54,245)	(54,649)	(55,053)	(55,457)	(55,861)	(56,265)	(56,669)	104,681	0	0	
3a	Regulatory Asset Balance (C)				0	0	0	0	0	0	0	0	0	0	0	95,958	87,234	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$108,721	$108,317	$107,913	$107,509	$107,105	$106,701	$106,297	$105,893	$105,489	$105,085	$104,681	$95,958	$87,234	
6	Average Net Investment					108,519	108,115	107,711	107,307	106,903	106,499	106,095	105,691	105,287	104,883	100,319	91,596	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		1.97%	1.89%		178	177	177	176	175	175	167	167	166	165	158	144	2,025
	b. Equity Component Grossed Up For Taxes		5.71%	5.77%		516	514	512	510	508	506	510	508	506	504	482	440	6,016
	c. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																	
	a. Depreciation	3.0000%				404	404	404	404	404	404	404	404	404	404	0	0	4,040
	b. Amortization (C)					0	0	0	0	0	0	0	0	0	0	8,723	8,723	17,447
	c. Dismantlement					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B)	0.008000				(222)	108	108	108	108	108	108	108	108	108	0	0	750
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					$876	$1,203	$1,201	$1,198	$1,195	$1,193	$1,189	$1,187	$1,184	$1,181	$9,363	$9,307	$30,278
	a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand					$876	$1,203	$1,201	$1,198	$1,195	$1,193	$1,189	$1,187	$1,184	$1,181	$9,363	$9,307	$30,278

For Project: CAIR CTs - BARTOW (Project 7.2b)
(in Dollars)

Line	Description	Rate	Jan-Jun	Jul-Dec	Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant					0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements					0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other					0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base				$275,347	$275,347	$275,347	$275,347	$275,347	$275,347	$275,347	$275,347	$275,347	$275,347	$275,347	$275,347	$275,347	
3	Less: Accumulated Depreciation				(62,449)	(62,807)	(63,165)	(63,523)	(63,881)	(64,239)	(64,597)	(64,955)	(65,313)	(65,671)	(66,029)	(66,387)	(66,745)	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$212,898	$212,540	$212,182	$211,824	$211,466	$211,108	$210,750	$210,392	$210,034	$209,676	$209,318	$208,960	$208,602	
6	Average Net Investment					212,719	212,361	212,003	211,645	211,287	210,929	210,571	210,213	209,855	209,497	209,139	208,781	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		1.97%	1.89%		349	348	347	347	346	346	332	331	331	330	330	329	4,066
	b. Equity Component Grossed Up For Taxes		5.71%	5.77%		1,011	1,010	1,008	1,006	1,005	1,003	1,013	1,011	1,009	1,007	1,006	1,004	12,093
	c. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																	
	a. Depreciation	1.5610%				358	358	358	358	358	358	358	358	358	358	358	358	4,296
	b. Amortization					0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B)	0.008150				(143)	187	187	187	187	187	187	187	187	187	187	187	1,914
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					$1,575	$1,903	$1,900	$1,898	$1,896	$1,894	$1,890	$1,887	$1,885	$1,882	$1,881	$1,878	$22,369
	a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand					$1,575	$1,903	$1,900	$1,898	$1,896	$1,894	$1,890	$1,887	$1,885	$1,882	$1,881	$1,878	$22,369

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.
(B) January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.
(C) Investment amortized over one year as approved in Order No. PSC-2019-0500-FOF-EI.

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2019 through December 2019
CAIR CTs (Project 7.2 Recap)

Docket No. 20210007-EI
Duke Energy Florida
Witness: G. P. Dean
Exh. No. __ (GPD-2)

For Project: CAIR CTs - BAYBORO (Project 7.2c)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	
3	Less: Accumulated Depreciation			(57,087)	(57,471)	(57,855)	(58,239)	(58,623)	(59,007)	(59,391)	(59,775)	(60,159)	(60,543)	(60,927)	(61,311)	(61,695)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$141,901	$141,517	$141,133	$140,749	$140,365	$139,981	$139,597	$139,213	$138,829	$138,445	$138,061	$137,677	$137,293	
6	Average Net Investment				141,709	141,325	140,941	140,557	140,173	139,789	139,405	139,021	138,637	138,253	137,869	137,485	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.97%	1.89%		232	232	231	230	230	229	220	219	218	218	217	217	2,693
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		674	672	670	668	666	665	670	669	667	665	663	661	8,010
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation 2.3149%				384	384	384	384	384	384	384	384	384	384	384	384	4,608
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B) 0.011030				(147)	183	183	183	183	183	183	183	183	183	183	183	1,866
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$1,143	$1,471	$1,468	$1,465	$1,463	$1,461	$1,457	$1,455	$1,452	$1,450	$1,447	$1,445	$17,177
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$1,143	$1,471	$1,468	$1,465	$1,463	$1,461	$1,457	$1,455	$1,452	$1,450	$1,447	$1,445	$17,177

For Project: CAIR CTs - DeBARY (Project 7.2d)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	
3	Less: Accumulated Depreciation			(32,655)	(32,874)	(33,093)	(33,312)	(33,531)	(33,750)	(33,969)	(34,188)	(34,407)	(34,626)	(34,845)	(35,064)	(35,283)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$55,012	$54,793	$54,574	$54,355	$54,136	$53,917	$53,698	$53,479	$53,260	$53,041	$52,822	$52,603	$52,384	
6	Average Net Investment				54,903	54,684	54,465	54,246	54,027	53,808	53,589	53,370	53,151	52,932	52,713	52,494	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.97%	1.89%		90	90	89	89	89	88	84	84	84	83	83	83	1,036
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		261	260	259	258	257	256	258	257	256	255	253	252	3,082
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation 3.0000%				219	219	219	219	219	219	219	219	219	219	219	219	2,628
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B) 0.008220				(270)	60	60	60	60	60	60	60	60	60	60	60	390
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$300	$629	$627	$626	$625	$623	$621	$620	$619	$617	$615	$614	$7,136
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$300	$629	$627	$626	$625	$623	$621	$620	$619	$617	$615	$614	$7,136

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.
(B) January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2019 through December 2019
CAIR CTs (Project 7.2 Recap)

Docket No. 20210007-EI
Duke Energy Florida
Witness: G. P. Dean
Exh. No. __ (GPD-2)
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For Project: CAIR CTs - HIGGINS (Project 7.2e)
(in Dollars)

Line	Description		Jan-Jun	Jul-Dec	Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant					0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements					0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other					0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base				$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation				0	0	0	0	0	0	0	0	0	0	0	0	0	
3a	Regulatory Asset Balance (C)				239,885	219,894	199,904	179,914	159,923	139,933	119,942	99,952	79,962	59,971	39,981	19,990	0	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$239,885	$219,894	$199,904	$179,914	$159,923	$139,933	$119,942	$99,952	$79,962	$59,971	$39,981	$19,990	$0	
6	Average Net Investment					229,890	209,899	189,909	169,918	149,928	129,938	109,947	89,957	69,966	49,976	29,986	9,995	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		1.97%	1.89%		377	344	311	278	246	213	173	142	110	79	47	16	2,336
	b. Equity Component Grossed Up For Taxes		5.71%	5.77%		1,093	998	903	808	713	618	529	433	336	240	144	48	6,863
	c. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																	
	a. Depreciation	2.9000%				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization (C)					19,990	19,990	19,990	19,990	19,990	19,990	19,990	19,990	19,990	19,990	19,990	19,990	239,885
	c. Dismantlement					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008270				0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					$21,460	$21,332	$21,204	$21,076	$20,949	$20,821	$20,692	$20,565	$20,436	$20,309	$20,181	$20,054	$249,084
	a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand					$21,460	$21,332	$21,204	$21,076	$20,949	$20,821	$20,692	$20,565	$20,436	$20,309	$20,181	$20,054	$249,084

For Project: CAIR CTs - INTERCESSION CITY (Project 7.2f)
(in Dollars)

Line	Description		Jan-Jun	Jul-Dec	Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant					0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements					0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other					0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base				$349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	
3	Less: Accumulated Depreciation				(113,899)	(114,686)	(115,473)	(116,260)	(117,047)	(117,834)	(118,621)	(119,408)	(120,195)	(120,982)	(121,769)	(122,556)	(123,343)	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$235,685	$234,898	$234,111	$233,324	$232,537	$231,750	$230,963	$230,176	$229,389	$228,602	$227,815	$227,028	$226,241	
6	Average Net Investment					235,291	234,504	233,717	232,930	232,143	231,356	230,569	229,782	228,995	228,208	227,421	226,634	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		1.97%	1.89%		386	384	383	382	380	379	363	362	361	360	358	357	4,455
	b. Equity Component Grossed Up For Taxes		5.71%	5.77%		1,119	1,115	1,111	1,108	1,104	1,100	1,109	1,105	1,101	1,097	1,094	1,090	13,253
	c. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																	
	a. Depreciation	2.7000%				787	787	787	787	787	787	787	787	787	787	787	787	9,444
	b. Amortization					0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007220				(120)	210	210	210	210	210	210	210	210	210	210	210	2,190
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					$2,172	$2,496	$2,491	$2,487	$2,481	$2,476	$2,469	$2,464	$2,459	$2,454	$2,449	$2,444	$29,342
	a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand					$2,172	$2,496	$2,491	$2,487	$2,481	$2,476	$2,469	$2,464	$2,459	$2,454	$2,449	$2,444	$29,342

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.
(B) January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.
(C) Investment amortized over one year as approved in Order No. PSC-2019-0500-FOF-EI.

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2019 through December 2019
CAIR CTs (Project 7.2 Recap)

For Project: CAIR CTs - SUWANNEE (Project 7.2h)
(in Dollars)

Line	Description		Jan-Jun	Jul-Dec	Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant					0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements					0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other					0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base				$381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	
3	Less: Accumulated Depreciation				(66,342)	(66,765)	(67,188)	(67,611)	(68,034)	(68,457)	(68,880)	(69,303)	(69,726)	(70,149)	(70,572)	(70,995)	(71,418)	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$315,218	$314,795	$314,372	$313,949	$313,526	$313,103	$312,680	$312,257	$311,834	$311,411	$310,988	$310,565	$310,142	
6	Average Net Investment					315,006	314,583	314,160	313,737	313,314	312,891	312,468	312,045	311,622	311,199	310,776	310,353	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		1.97%	1.89%		516	516	515	514	513	513	492	492	491	490	490	489	6,031
	b. Equity Component Grossed Up For Taxes		5.71%	5.77%		1,498	1,496	1,494	1,492	1,490	1,488	1,503	1,501	1,498	1,496	1,494	1,492	17,942
	c. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																	
	a. Depreciation	1.3299%				423	423	423	423	423	423	423	423	423	423	423	423	5,076
	b. Amortization					0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B)	0.008390				(63)	267	267	267	267	267	267	267	267	267	267	267	2,874
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					$2,374	$2,702	$2,699	$2,696	$2,693	$2,691	$2,685	$2,683	$2,679	$2,676	$2,674	$2,671	$31,923
	a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand					$2,374	$2,702	$2,699	$2,696	$2,693	$2,691	$2,685	$2,683	$2,679	$2,676	$2,674	$2,671	$31,923

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.
(B) January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.

For Project: CAIR Crystal River - FGD Common (Project 7.4d)
(in Dollars)

Line Description	Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1 Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base	$2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	
3 Less: Accumulated Depreciation	(235,217)	(239,641)	(244,065)	(248,489)	(252,913)	(257,337)	(261,761)	(266,185)	(270,609)	(275,033)	(279,457)	(283,881)	(288,305)	
4 CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)	$1,913,883	$1,909,459	$1,905,035	$1,900,611	$1,896,187	$1,891,763	$1,887,339	$1,882,915	$1,878,491	$1,874,067	$1,869,643	$1,865,219	$1,860,795	
6 Average Net Investment		1,911,671	1,907,247	1,902,823	1,898,399	1,893,975	1,889,551	1,885,127	1,880,703	1,876,279	1,871,855	1,867,431	1,863,007	
7 Return on Average Net Investment (A) Jan-Jun Jul-Dec														
a. Debt Component 1.97% 1.89%		3,133	3,126	3,119	3,111	3,104	3,097	2,971	2,964	2,957	2,950	2,943	2,936	36,411
b. Equity Component Grossed Up For Taxes 5.71% 5.77%		9,090	9,069	9,048	9,027	9,005	8,984	9,065	9,044	9,022	9,001	8,980	8,959	108,294
c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses														
a. Depreciation 2.4700%		4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	53,088
b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes (B) 0.000525		(317)	94	94	94	94	94	94	94	94	94	94	94	717
e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)		$16,330	$16,713	$16,685	$16,656	$16,627	$16,599	$16,554	$16,526	$16,497	$16,469	$16,441	$16,413	$198,510
a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand		$16,330	$16,713	$16,685	$16,656	$16,627	$16,599	$16,554	$16,526	$16,497	$16,469	$16,441	$16,413	$198,510

For Project: Crystal River 4 and 5 - Conditions of Certification (Project 7.4q)
(in Dollars)

Line Description	Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1 Investments														
a. Expenditures/Additions		$159,014	($1,299)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$157,716
b. Clearings to Plant		159,014	(1,299)	0	0	0	0	0	0	0	0	0	0	
c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base	$83,225,983	83,384,998	83,383,699	83,383,699	83,383,699	83,383,699	83,383,699	83,383,699	83,383,699	83,383,699	83,383,699	83,383,699	83,383,699	
3 Less: Accumulated Depreciation	(1,166,676)	(1,269,934)	(1,373,191)	(1,476,448)	(1,579,705)	(1,682,962)	(1,786,219)	(1,889,476)	(1,992,733)	(2,095,990)	(2,199,247)	(2,302,504)	(2,405,761)	
4 CWIP - Non-Interest Bearing	0	(0)	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)	$82,059,307	$82,115,063	$82,010,508	$81,907,251	$81,803,994	$81,700,737	$81,597,480	$81,494,223	$81,390,966	$81,287,709	$81,184,452	$81,081,195	$80,977,938	
6 Average Net Investment		82,087,185	82,062,786	81,958,879	81,855,622	81,752,365	81,649,108	81,545,851	81,442,594	81,339,337	81,236,080	81,132,823	81,029,566	
7 Return on Average Net Investment (A) Jan-Jun Jul-Dec														
a. Debt Component 1.97% 1.89%		134,534	134,494	134,324	134,155	133,985	133,816	128,509	128,347	128,184	128,021	127,859	127,696	1,573,924
b. Equity Component Grossed Up For Taxes 5.71% 5.77%		390,309	390,193	389,699	389,208	388,717	388,226	392,128	391,632	391,135	390,639	390,142	389,646	4,681,674
c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses														
a. Depreciation 1.4860%		103,258	103,257	103,257	103,257	103,257	103,257	103,257	103,257	103,257	103,257	103,257	103,257	1,239,085
b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes (B) 0.000525		(12,318)	3,647	3,647	3,647	3,647	3,647	3,647	3,647	3,647	3,647	3,647	3,647	27,799
e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)		$615,783	$631,591	$630,927	$630,267	$629,606	$628,946	$627,541	$626,883	$626,223	$625,564	$624,905	$624,246	$7,522,482
a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand		$615,783	$631,591	$630,927	$630,267	$629,606	$628,946	$627,541	$626,883	$626,223	$625,564	$624,905	$624,246	$7,522,482

Note> Consistent with the Stipulation & Settlement Agreement in Order No. PSC-2013-0598-FOF-EI these assets were not projected to be in-service as of year end 2013 and accordingly were not moved to base rates in 2014.
(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.
(B) January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.

For Project: CAIR Crystal River - FGD Common (Project 7.4r) - CR4 Clinker Mitigation
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$660,998	660,998	660,998	660,998	660,998	660,998	660,998	660,998	660,998	660,998	660,998	660,998	660,998	
3	Less: Accumulated Depreciation			(104,197)	(105,558)	(106,919)	(108,280)	(109,641)	(111,002)	(112,363)	(113,724)	(115,085)	(116,446)	(117,807)	(119,168)	(120,529)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$556,801	$555,440	$554,079	$552,718	$551,357	$549,996	$548,635	$547,274	$545,913	$544,552	$543,191	$541,830	$540,469	
6	Average Net Investment				556,121	554,760	553,399	552,038	550,677	549,316	547,955	546,594	545,233	543,872	542,511	541,150	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.97%	1.89%		911	909	907	905	903	900	864	861	859	857	855	853	10,584
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		2,644	2,638	2,631	2,625	2,618	2,612	2,635	2,628	2,622	2,615	2,609	2,602	31,479
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation 2.4700%				1,361	1,361	1,361	1,361	1,361	1,361	1,361	1,361	1,361	1,361	1,361	1,361	16,332
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B) 0.000525				(98)	29	29	29	29	29	29	29	29	29	29	29	221
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$4,818	$4,937	$4,928	$4,920	$4,911	$4,902	$4,889	$4,879	$4,871	$4,862	$4,854	$4,845	$58,616
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$4,818	$4,937	$4,928	$4,920	$4,911	$4,902	$4,889	$4,879	$4,871	$4,862	$4,854	$4,845	$58,616

For Project: CAIR Crystal River - FGD Common (Project 7.4s) - CR5 Clinker Mitigation
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$505,904	505,904	505,904	505,904	505,904	505,904	505,904	505,904	505,904	505,904	505,904	505,904	505,904	
3	Less: Accumulated Depreciation			(66,823)	(67,864)	(68,905)	(69,946)	(70,987)	(72,028)	(73,069)	(74,110)	(75,151)	(76,192)	(77,233)	(78,274)	(79,315)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$439,081	$438,040	$436,999	$435,958	$434,917	$433,876	$432,835	$431,794	$430,753	$429,712	$428,671	$427,630	$426,589	
6	Return on Average Net Investment (A)				438,561	437,520	436,479	435,438	434,397	433,356	432,315	431,274	430,233	429,192	428,151	427,110	
7	Return on Average Net Investment	Jan-Jun	Jul-Dec														
	a. Debt Component	1.97%	1.89%		719	717	715	714	712	710	681	680	678	676	675	673	8,350
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		2,085	2,080	2,075	2,070	2,065	2,061	2,079	2,074	2,069	2,064	2,059	2,054	24,835
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation 2.4700%				1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	12,492
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B) 0.000525				(75)	22	22	22	22	22	22	22	22	22	22	22	167
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$3,770	$3,860	$3,853	$3,847	$3,840	$3,834	$3,823	$3,817	$3,810	$3,803	$3,797	$3,790	$45,844
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$3,770	$3,860	$3,853	$3,847	$3,840	$3,834	$3,823	$3,817	$3,810	$3,803	$3,797	$3,790	$45,844

Note> Consistent with the Stipulation & Settlement Agreement in Order No. PSC-2013-0598-FOF-EI these assets were not projected to be in-service as of year end 2013 and accordingly were not moved to base rates in 2014.
(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.
(B) January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Commission Forms 42-1E Through 42-9E

January 2021 - December 2021
Calculation for the Current Period Actual / Estimated Amount
Actuals for the Period January 2021 - June 2021
Estimates for the Period July 2021 - December 2021

Docket No. 20210007-EI

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2021 - December 2021
(in Dollars)

Line		Period Amount
1	Over/(Under) Recovery for the Period (Form 42-2E, Line 5)	$ 1,593,352
2	Interest Provision (Form 42-2E, Line 6)	3,398
3	Sum of Current Period Adjustments (Form 42-2E, Line 10)	0
4	Final True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2022 to December 2022 (Lines 1 + 2 + 3)	$ 1,596,750

Form 42-2E

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2021 - December 2021

Docket No. 20210007-EI
Duke Energy Florida
Witness: G. P. Dean
Exh. No. __ (GPD-3)

End-of-Period True-Up Amount
(in Dollars)

Line	Description		Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	ECRC Revenues (net of Revenue Taxes)		$2,802,398	$2,669,202	$2,810,085	$2,865,581	$3,072,006	$3,585,155	$3,709,253	$3,808,179	$3,744,870	$3,491,142	$2,898,735	$2,743,599	$38,200,205
2	True-Up Provision (Order No. PSC-2020-0433-FOF-EI)	6,304,739	525,395	525,395	525,395	525,395	525,395	525,395	525,395	525,395	525,395	525,395	525,395	525,395	6,304,739
3	ECRC Revenues Applicable to Period (Lines 1 + 2)		$3,327,793	3,194,597	3,335,480	3,390,976	3,597,401	4,110,549	4,234,648	4,333,573	4,270,265	4,016,537	3,424,130	3,268,994	44,504,944
4	Jurisdictional ECRC Costs														
	a. O & M Activities (Form 42-5E, Line 9)		$1,304,079	1,392,141	1,779,954	1,899,078	1,634,092	1,710,610	1,817,676	1,551,769	1,603,917	2,077,807	1,436,751	1,553,098	19,760,972
	b. Capital Investment Projects (Form 42-7E, Line 9)		1,917,534	1,959,855	1,959,429	1,945,298	1,906,387	1,893,763	1,895,312	1,898,460	1,917,502	1,949,880	1,945,168	1,962,032	23,150,620
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Total Jurisdictional ECRC Costs		$3,221,613	$3,351,996	$3,739,383	$3,844,376	$3,540,479	$3,604,373	$3,712,988	$3,450,229	$3,521,419	$4,027,687	$3,381,919	$3,515,130	$42,911,592
5	Over/(Under) Recovery (Line 3 - Line 4d)		$106,180	(157,399)	(403,903)	(453,401)	56,922	506,177	521,660	883,345	748,846	(11,150)	42,212	(246,137)	$1,593,352
6	Interest Provision (Form 42-3E, Line 10)		569	520	398	321	165	153	213	225	245	235	199	155	3,398
7	Beginning Balance True-Up & Interest Provision		6,304,739	5,886,093	5,203,819	4,274,919	3,296,445	2,828,136	2,809,071	2,805,549	3,163,724	3,387,420	2,851,111	2,368,126	6,304,739
	a. Deferred True-Up - January 2020 to December 2020 (2020 TU filing dated April 1, 2021)		231,488	231,488	231,488	231,488	231,488	231,488	231,488	231,488	231,488	231,488	231,488	231,488	231,488
8	True-Up Collected/(Refunded) (Line 2)		(525,395)	(525,395)	(525,395)	(525,395)	(525,395)	(525,395)	(525,395)	(525,395)	(525,395)	(525,395)	(525,395)	(525,395)	(6,304,739)
9	End of Period Total True-Up (Lines 5+6+7+7a+8)		$6,117,581	5,435,307	4,506,407	3,527,932	3,059,624	3,040,559	3,037,037	3,395,212	3,618,908	3,082,598	2,599,614	1,828,238	$1,828,238
10	Adjustments to Period Total True-Up Including Interest		0	0	0	0	0	0	0	0	0	0	0	0	0
11	End of Period Total True-Up (Over/(Under) (Lines 9 + 10)		$6,117,581	$5,435,307	$4,506,407	$3,527,932	$3,059,624	$3,040,559	3,037,037	$3,395,212	$3,618,908	$3,082,598	$2,599,614	$1,828,238	$1,828,238

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2021 - December 2021

Interest Provision
(in Dollars)

Line	Description	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Beginning True-Up Amount (Form 42-2E, Lines 7 + 7a + 10)	$6,536,227	$6,117,581	$5,435,307	$4,506,407	$3,527,932	$3,059,624	$3,040,559	$3,037,037	$3,395,212	$3,618,908	$3,082,598	$2,599,614	
2	Ending True-Up Amount Before Interest (Line 1 + Form 42-2E, Lines 5 + 8)	6,117,012	5,434,787	4,506,009	3,527,611	3,059,459	3,040,406	3,036,824	3,394,987	3,618,663	3,082,363	2,599,415	1,828,083	
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	12,653,239	11,552,368	9,941,316	8,034,018	6,587,392	6,100,030	6,077,383	6,432,024	7,013,875	6,701,271	5,682,013	4,427,697	
4	Average True-Up Amount (Line 3 x 1/2)	6,326,620	5,776,184	4,970,658	4,017,009	3,293,696	3,050,015	3,038,692	3,216,012	3,506,938	3,350,636	2,841,007	2,213,849	
5	Interest Rate (Last Business Day of Prior Month)	0.10%	0.12%	0.09%	0.11%	0.07%	0.04%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	
6	Interest Rate (Last Business Day of Current Month)	0.12%	0.09%	0.11%	0.07%	0.04%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	0.08%	
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	0.22%	0.21%	0.20%	0.18%	0.11%	0.12%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	
8	Average Interest Rate (Line 7 x 1/2)	0.110%	0.105%	0.100%	0.090%	0.055%	0.060%	0.080%	0.080%	0.080%	0.080%	0.080%	0.080%	
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.009%	0.009%	0.008%	0.008%	0.005%	0.005%	0.007%	0.007%	0.007%	0.007%	0.007%	0.007%	
10	Interest Provision for the Month (Line 4 x Line 9)	$569	$520	$398	$321	$165	$153	$213	$225	$245	$235	$199	$155	3,398

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2021 - December 2021

Docket No. 20210007-EI
Duke Energy Florida
Witness: G. P. Dean
Exh. No. __ (GPD-3)

Variance Report of O&M Activities
(In Dollars)

Line		Description	(1) Actual / Estimated	(2) Projection Filing	(3) Variance Amount	(4) Variance Percent
1		O&M Activities - System				
	1	Transmission Substation Environmental Investigation, Remediation and Pollution Prevention	$263	$3,000	($2,738)	-91%
	1a	Distribution Substation Environmental Investigation, Remediation and Pollution Prevention	0	0	0	0%
	2	Distribution System Environmental Investigation, Remediation and Pollution Prevention	0	0	0	0%
	3	Pipeline Integrity Management - Bartow /Anclote Pipeline - Intm	0	0	0	0%
	4	Above Ground Tank Secondary Containment	0	0	0	0%
	5	SO2/NOx Emissions Allowances - Energy	12,245	9,913	2,332	24%
	6	Phase II Cooling Water Intake 316(b) - Base	1,003	5,000	(3,997)	-80%
	6.a	Phase II Cooling Water Intake 316(b) - Intm	28,997	30,000	(1,003)	-3%
	7.2	CAIR/CAMR - Peaking	0	0	0	0%
	7.4	CAIR/CAMR Crystal River - Base	13,600,940	13,395,613	205,327	2%
	7.4	CAIR/CAMR Crystal River - Energy	4,966,961	6,295,908	(1,328,948)	-21%
	7.4	CAIR/CAMR Crystal River - A&G	79,837	79,837	(0)	0%
	7.4	CAIR/CAMR Crystal River - Conditions of Certification - Energy	1,209,418	1,800,000	(590,582)	-33%
	7.5	Best Available Retrofit Technology (BART) - Energy	0	0	0	0%
	8	Arsenic Groundwater Standard - Base	268,931	275,000	(6,069)	-2%
	9	Sea Turtle - Coastal Street Lighting - Distrib	0	600	(600)	-100%
	11	Modular Cooling Towers - Base	0	0	0	0%
	12	Greenhouse Gas Inventory and Reporting - Energy	0	0	0	0%
	13	Mercury Total Daily Maximum Loads Monitoring - Energy	0	0	0	0%
	14	Hazardous Air Pollutants (HAPs) ICR Program - Energy	0	0	0	0%
	15	Effluent Limitation Guidelines ICR Program - Energy	0	0	0	0%
	15.1	Effluent Limitation Guidelines Program CRN - Energy	0	0	0	0%
	16	National Pollutant Discharge Elimination System (NPDES) - Energy	51,635	31,500	20,135	64%
	17	Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy	245,000	360,000	(115,000)	-32%
	17.1	Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion - Energy	0	0	0	0%
	17.2	Mercury & Air Toxic Standards (MATS) CR1 & CR2 - Energy	0	0	0	0%
	18	Coal Combustion Residual (CCR) Rule - Energy	752,478	278,000	474,478	171%
2		Total O&M Activities - Recoverable Costs	$21,217,707	$22,564,371	($1,346,664)	-6%
3		Recoverable Costs Allocated to Energy	7,237,736	8,775,321	(1,537,585)	-18%
4		Recoverable Costs Allocated to Demand	$13,979,970	$13,789,050	$190,920	1%

Notes:

Column (1) End of Period Totals on Form 42-5E
Column (2) 2021 Projection Filing Form 42-2P
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Form 42-5E

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2021 - December 2021

Docket No. 20210007-EI
Duke Energy Florida
Witness: G. P. Dean
Exh. No. __ (GPD-3)

O&M Activities
(in Dollars)

Line		Description	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1		O&M Activities - System													
	1	Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$263	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$263
	1a	Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	0	0	0	0	0	0	0	0	0	0	0	0	0
	2	Distribution System Environmental Investigation, Remediation, and Pollution Prevention	0	0	0	0	0	0	0	0	0	0	0	0	0
	3	Pipeline Integrity Management - Bartow/Anclote Pipeline - Intm	0	0	0	0	0	0	0	0	0	0	0	0	0
	4	Above Ground Tank Secondary Containment - Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0
	5	SO2/NOx Emissions Allowances - Energy	276	448	824	681	1,031	(40)	1,735	1,680	1,680	1,649	988	1,292	12,245
	6	Phase II Cooling Water Intake 316(b) - Base	1,003	0	0	0	0	0	0	0	0	0	0	0	1,003
	6a	Phase II Cooling Water Intake 316(b) - Intm	(1,003)	0	0	0	0	0	0	0	0	0	0	30,000	28,997
	7.2	CAIR/CAMR - Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0
	7.4	CAIR/CAMR Crystal River - Base	971,185	825,216	954,368	1,112,034	921,686	982,124	1,380,202	1,063,061	1,153,252	1,637,992	1,272,036	1,327,784	13,600,940
	7.4	CAIR/CAMR Crystal River - Energy	295,089	499,910	265,281	748,567	726,207	629,684	444,653	479,415	381,929	352,939	70,680	72,606	4,966,961
	7.4	CAIR/CAMR Crystal River - A&G	7,638	4,050	6,765	6,716	5,946	9,760	6,703	6,904	7,111	7,325	7,544	3,375	79,837
	7.4	CAIR/CAMR Crystal River - Conditions of Certification - Energy	41,416	75,198	146,472	74,334	63,763	208,235	100,000	100,000	100,000	100,000	100,000	100,000	1,209,418
	7.5	Best Available Retrofit Technology (BART) - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	8	Arsenic Groundwater Standard - Base	(4,753)	32,371	114,849	43,917	17,362	33,185	8,750	4,000	2,250	6,750	4,000	6,250	268,931
	9	Sea Turtle - Coastal Street Lighting - Distrib	0	0	0	0	0	0	0	0	0	0	0	0	0
	11	Modular Cooling Towers - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
	12	Greenhouse Gas Inventory and Reporting - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	13	Mercury Total Daily Maximum Loads Monitoring - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	14	Hazardous Air Pollutants (HAPs) ICR Program - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	15	Effluent Limitation Guidelines ICR Program - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	15.1	Effluent Limitation Guidelines Program CRN - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	16	National Pollutant Discharge Elimination System (NPDES) - Energy	25,123	0	0	4,453	312	0	1,347	0	9,800	10,600	0	0	51,635
	17	Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy	0	0	0	0	0	0	0	0	50,000	65,000	65,000	65,000	245,000
	17.1	Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	17.2	Mercury & Air Toxic Standards (MATS) CR1 & CR2 - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	18	Coal Combustion Residual (CCR) Rule - Energy	65,918	33,350	391,238	28,508	31,931	(562)	25,930	29,429	22,059	45,559	20,059	59,059	752,478
2		Total O&M Activities - Recoverable Costs	$1,402,155	$1,470,544	$1,879,798	$2,019,211	$1,768,237	$1,862,386	$1,969,320	$1,684,489	$1,728,082	$2,227,814	$1,540,307	$1,665,366	$21,217,707
3		Recoverable Costs Allocated to Energy	427,822	608,906	803,816	856,543	823,243	837,317	573,665	610,524	565,469	575,747	256,727	297,957	7,237,736
4		Recoverable Costs Allocated to Demand - Transm	263	0	0	0	0	0	0	0	0	0	0	0	263
		Recoverable Costs Allocated to Demand - Distrib	0	0	0	0	0	0	0	0	0	0	0	0	0
		Recoverable Costs Allocated to Demand - Prod-Base	967,435	857,587	1,069,217	1,155,951	939,048	1,015,309	1,388,952	1,067,061	1,155,502	1,644,742	1,276,036	1,334,034	13,870,873
		Recoverable Costs Allocated to Demand - Prod-Intm	(1,003)	0	0	0	0	0	0	0	0	0	0	30,000	28,997
		Recoverable Costs Allocated to Demand - Prod-Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0
		Recoverable Costs Allocated to Demand - A&G	7,638	4,050	6,765	6,716	5,946	9,760	6,703	6,904	7,111	7,325	7,544	3,375	79,837
5		Retail Energy Jurisdictional Factor	0.93240	0.97190	0.97100	0.95630	0.91870	0.90580	0.90872	0.90773	0.92667	0.94357	0.95226	0.97002	
6		Retail Transmission Demand Jurisdictional Factor	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	
		Retail Distribution Demand Jurisdictional Factor	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	
		Retail Production Demand Jurisdictional Factor - Base	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
		Retail Production Demand Jurisdictional Factor - Intm	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
		Retail Production Demand Jurisdictional Factor - Peaking	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	
		Retail Production Demand Jurisdictional Factor - A&G	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	
7		Jurisdictional Energy Recoverable Costs (A)	398,902	591,796	780,505	819,112	756,314	758,442	521,299	554,193	524,000	543,260	244,472	289,024	6,781,319
8		Jurisdictional Demand Recoverable Costs - Transm (B)	184	0	0	0	0	0	0	0	0	0	0	0	184
		Jurisdictional Demand Recoverable Costs - Distrib (B)	0	0	0	0	0	0	0	0	0	0	0	0	0
		Jurisdictional Demand Recoverable Costs - Prod-Base (B)	898,602	796,569	993,142	1,073,705	872,235	943,070	1,290,128	991,140	1,073,288	1,527,719	1,185,246	1,239,117	12,883,961
		Jurisdictional Demand Recoverable Costs - Prod-Intm (B)	(729)	0	0	0	0	0	0	0	0	0	0	21,811	21,082
		Jurisdictional Demand Recoverable Costs - Prod-Peaking (B)	0	0	0	0	0	0	0	0	0	0	0	0	0
		Jurisdictional Demand Recoverable Costs - A&G (B)	7,120	3,776	6,307	6,261	5,543	9,098	6,249	6,436	6,629	6,828	7,033	3,146	74,426
9		Total Jurisdictional Recoverable Costs - O&M Activities (Lines 7 + 8)	$1,304,079	$1,392,141	$1,779,954	$1,899,078	$1,634,092	$1,710,610	$1,817,676	$1,551,769	$1,603,917	$2,077,807	$1,436,751	$1,553,098	$19,760,972

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2021 - December 2021

Variance Report of Capital Investment Activities
(in Dollars)

Line		Description	(1) Actual / Estimated	(2) Projection Filing	(3) Variance Amount	(4) Variance Percent
1		Capital Investment Activities - System				
	3.1	Pipeline Integrity Management - Bartow/Anclote Pipeline	$0	$0	$0	0%
	4.x	Above Ground Tank Secondary Containment	1,042,391	1,052,497	(10,106)	-1%
	5	SO2/NOx Emissions Allowances	250,823	255,020	(4,197)	-2%
	6.x	Phase II Cooling Water Intake 316(b) - Base	931,306	1,076,924	(145,618)	-14%
	7.x	CAIR/CAMR	8,284,254	8,186,248	98,006	1%
	9	Sea Turtle - Coastal Street Lighting	962	1,007	(45)	-4%
	10.x	Underground Storage Tanks	18,184	20,470	(2,286)	-11%
	11	Modular Cooling Towers	0	0	0	0%
	11.1	Crystal River Thermal Discharge Compliance Project	0	0	0	0%
	15.1	Effluent Limitation Guidelines CRN (ELG)	264,147	271,577	(7,430)	-3%
	16	National Pollutant Discharge Elimination System (NPDES)	1,316,425	1,329,392	(12,967)	-1%
	17x	Mercury & Air Toxics Standards (MATS)	12,595,885	12,797,863	(201,978)	-2%
	18	Coal Combustion Residual (CCR) Rule	339,625	183,829	155,796	85%
2		Total Capital Investment Activities - Recoverable Costs	$25,044,001	$25,174,826	($130,825)	-1%
3		Recoverable Costs Allocated to Energy	$13,083,672	$13,093,989	($10,317)	0%
4		Recoverable Costs Allocated to Demand	$11,960,329	$12,080,838	($120,508)	-1%

Notes:
Column (1) End of Period Totals on Form 42-7E
Column (2) 2021 Projection Filing Form 42-3P
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2021 - December 2021

Capital Investment Projects-Recoverable Costs
(in Dollars)

Form 42-7E

Docket No. 20210007-EI
Duke Energy Florida
Witness: G. P. Dean
Exh. No. __ (GPD-3)

Line	Description	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investment Projects - System (A)													
3.1	Pipeline Integrity Management - Bartow/Anclote Pipeline - Intermediate	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.1	Above Ground Tank Secondary Containment - Peaking	69,024	68,825	68,623	68,420	68,220	68,019	67,820	67,615	67,416	67,215	61,639	61,474	804,314
4.2	Above Ground Tank Secondary Containment - Base	18,006	17,986	17,967	17,948	17,929	17,911	17,891	17,872	17,853	17,834	17,815	17,796	214,808
4.3	Above Ground Tank Secondary Containment - Intermediate	1,958	1,954	1,951	1,948	1,944	1,941	1,937	1,934	1,931	1,927	1,923	1,921	23,269
5	SO2/NOX Emissions Allowances - Energy	20,932	20,931	20,926	20,922	20,915	20,913	20,906	20,896	20,885	20,874	20,865	20,858	250,823
6	Phase II Cooling Water Intake 316(b) - Base	67,446	68,221	68,962	69,713	71,044	72,520	73,856	75,261	76,333	94,359	96,623	96,968	931,306
6.1	Phase II Cooling Water Intake 316(b) - Base - Bartow	0	0	0	0	0	0	0	0	0	0	0	0	0
6.2	Phase II Cooling Water Intake 316(b) - Intermediate - Anclote	0	0	0	0	0	0	0	0	0	0	0	0	0
7.1	CAIR/CAMR Anclote- Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0
7.2	CAIR/CAMR - Peaking	18,409	18,337	18,266	18,195	18,126	18,054	17,984	17,912	17,842	17,773	9,006	8,992	198,900
7.3	CAMR Crystal River - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
7.4	CAIR/CAMR Crystal River AFUDC - Base	657,966	657,252	656,536	655,821	655,106	654,388	653,675	652,959	652,244	651,529	650,815	650,098	7,848,389
7.4	CAIR/CAMR Crystal River AFUDC - Energy	17,459	17,795	18,419	19,511	20,849	22,264	21,384	19,857	19,857	19,857	19,857	19,857	236,965
7.5	Best Available Retrofit Technology (BART) - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Sea Turtle - Coastal Street Lighting -Distribution	81	81	81	81	80	80	80	80	80	80	80	78	962
10.1	Underground Storage Tanks - Base	1,055	1,053	1,051	1,049	1,047	1,045	1,044	1,041	1,040	1,037	1,036	1,033	12,531
10.2	Underground Storage Tanks - Intermediate	478	477	476	474	473	472	470	469	468	467	465	464	5,653
11	Modular Cooling Towers - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
11.1	Crystal River Thermal Discharge Compliance Project - Base (Post 2012)	0	0	0	0	0	0	0	0	0	0	0	0	0
11.1	Crystal River Thermal Discharge Compliance Project - Base (2012)	0	0	0	0	0	0	0	0	0	0	0	0	0
15.1	Effluent Limitation Guidelines CRN (ELG) - Base	22,204	22,170	22,135	22,099	22,064	22,030	21,995	21,960	21,925	21,890	21,855	21,820	264,147
16	National Pollutant Discharge Elimination System (NPDES) - Intermediate	110,977	110,745	110,514	110,281	110,050	109,818	109,586	109,354	109,122	108,891	108,659	108,428	1,316,425
17	Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy	27,337	27,295	27,252	27,209	27,167	27,123	27,081	27,038	26,996	26,952	26,910	26,868	325,232
17.1	Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion - Energy	1,031,219	1,029,644	1,028,068	1,026,493	1,024,917	1,023,342	1,021,767	1,020,192	1,018,617	1,017,042	1,015,466	1,013,891	12,270,652
17.2	Mercury & Air Toxic Standards (MATS) CR1 & CR2 - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Coal Combustion Residual (CCR) Rule - Base	17,449	18,165	20,310	23,458	26,044	27,607	28,187	35,653	35,764	35,713	35,663	35,612	339,625
2	Total Investment Projects - Recoverable Costs	$2,082,001	$2,080,932	$2,081,538	$2,083,622	$2,085,976	$2,087,528	$2,085,664	$2,090,093	$2,088,373	$2,103,440	$2,088,677	$2,086,158	$25,044,001
3	Recoverable Costs Allocated to Energy	1,096,947	1,095,665	1,094,665	1,094,134	1,093,848	1,093,642	1,091,138	1,087,983	1,086,355	1,084,725	1,083,098	1,081,474	13,083,672
	Recoverable Costs Allocated to Distribution Demand	81	81	81	81	80	80	80	80	80	80	80	78	962
4	Recoverable Costs Allocated to Demand - Production - Base	784,126	784,847	786,961	790,088	793,234	795,501	796,648	804,746	805,159	822,362	823,807	823,327	9,610,806
	Recoverable Costs Allocated to Demand - Production - Intermediate	113,413	113,176	112,941	112,703	112,467	112,231	111,993	111,757	111,521	111,285	111,047	110,813	1,345,347
	Recoverable Costs Allocated to Demand - Production - Peaking	87,434	87,163	86,890	86,616	86,347	86,074	85,805	85,528	85,259	84,989	70,645	70,466	1,003,214
5	Retail Energy Jurisdictional Factor	0.93240	0.97190	0.97100	0.95630	0.91870	0.90580	0.90872	0.90773	0.92667	0.94357	0.95226	0.97002	
	Retail Distribution Demand Jurisdictional Factor	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	
6	Retail Demand Jurisdictional Factor - Production - Base	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
	Retail Demand Jurisdictional Factor - Production - Intermediate	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
	Retail Demand Jurisdictional Factor - Production - Peaking	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	
7	Jurisdictional Energy Recoverable Costs (B)	1,022,793	1,064,877	1,062,920	1,046,321	1,004,918	990,621	991,536	987,599	1,006,688	1,023,517	1,031,395	1,049,049	12,282,234
	Jurisdictional Demand Recoverable Costs - Distribution (B)	81	81	81	81	80	80	80	80	80	80	80	78	958
8	Jurisdictional Demand Recoverable Costs - Production - Base (C)	728,335	729,005	730,969	733,873	736,795	738,901	739,966	747,488	747,872	763,851	765,193	764,747	8,926,997
	Jurisdictional Demand Recoverable Costs - Production - Intermediate (C)	82,455	82,282	82,111	81,938	81,767	81,595	81,422	81,251	81,079	80,908	80,735	80,564	978,108
	Jurisdictional Demand Recoverable Costs - Production - Peaking (C)	83,870	83,610	83,348	83,085	82,827	82,565	82,307	82,042	81,784	81,525	67,766	67,594	962,323
9	Total Jurisdictional Recoverable Costs - Investment Projects (Lines 7 + 8)	$1,917,534	$1,959,855	$1,959,429	$1,945,298	$1,906,387	$1,893,763	$1,895,312	$1,898,460	$1,917,502	$1,949,880	$1,945,168	$1,962,032	$23,150,620

Notes:

(A) Each project's Total System Recoverable Expenses on Form 42-8E, Line 9; Form 42-8E, Line 5 for Projects 5 - Emission Allowances and Project 7. 4 - Reagents.
(B) Line 3 x Line 5
(C) Line 4 x Line 6

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2021 - December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Peaking (Project 4.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (A)		$8,661,298	$8,661,298	$8,661,298	$8,661,298	$8,661,298	$8,661,298	$8,661,298	$8,661,298	$8,661,298	$8,661,298	$8,661,298	$8,661,298	$8,661,298	
3	Less: Accumulated Depreciation		(3,722,253)	(3,747,829)	(3,773,405)	(3,798,981)	(3,824,557)	(3,850,133)	(3,875,709)	(3,901,285)	(3,926,861)	(3,952,436)	(3,978,013)	(4,003,589)	(4,029,165)	
3a	Regulatory Asset Balance (G)		53,914	48,523	43,131	37,740	32,349	26,957	21,566	16,174	10,783	5,391	0	0	0	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$4,992,960	$4,961,993	$4,931,025	$4,900,058	$4,869,090	$4,838,123	$4,807,155	$4,776,188	$4,745,221	$4,714,253	$4,683,286	$4,657,710	$4,632,134	
6	Average Net Investment			$4,977,476	$4,946,509	$4,915,541	$4,884,574	$4,853,607	$4,822,639	$4,791,672	$4,760,704	$4,729,737	$4,698,769	$4,670,498	$4,644,922	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.72%		7,148	7,104	7,058	7,014	6,970	6,926	6,882	6,836	6,793	6,749	6,706	6,671	82,857
	b. Equity Component Grossed Up For Taxes	6.07%		25,195	25,040	24,884	24,725	24,569	24,412	24,257	24,098	23,942	23,785	23,643	23,513	292,063
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			25,576	25,576	25,576	25,576	25,576	25,576	25,576	25,576	25,576	25,576	25,576	25,576	306,912
	b. Amortization (G)			5,391	5,391	5,391	5,391	5,391	5,391	5,391	5,391	5,391	5,391	0	0	53,914
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes			5,714	5,714	5,714	5,714	5,714	5,714	5,714	5,714	5,714	5,714	5,714	5,714	68,568
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$69,024	$68,825	$68,623	$68,420	$68,220	$68,019	$67,820	$67,615	$67,416	$67,215	$61,639	$61,474	804,314
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			69,024	68,825	68,623	68,420	68,220	68,019	67,820	67,615	67,416	67,215	61,639	61,474	804,314
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Peaking)			0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)			66,211	66,020	65,826	65,632	65,440	65,247	65,056	64,859	64,669	64,476	59,127	58,968	771,530
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$66,211	$66,020	$65,826	$65,632	$65,440	$65,247	$65,056	$64,859	$64,669	$64,476	$59,127	$58,968	$771,530

Notes:

(A) N/A
(B) Line 6 x 7.80% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.52% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology.
(C) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets in-service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 Rate Case Order PSC-2010-0131-FOF-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets in-service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2020 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11
(G) Project 4.1d (Avon Park) amortized over one year as approved in Order No. PSC-2019-0500-FOF-EI.

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2021 - December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Base (Project 4.2)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	
3	Less: Accumulated Depreciation		($59,908)	($62,838)	($65,768)	($68,698)	($71,628)	($74,558)	($77,488)	($80,418)	($83,348)	($86,278)	($89,208)	($92,138)	($95,068)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$2,306,039	$2,303,109	$2,300,179	$2,297,249	$2,294,319	$2,291,389	$2,288,459	$2,285,529	$2,282,599	$2,279,669	$2,276,739	$2,273,809	$2,270,879	
6	Average Net Investment			$2,304,574	$2,301,644	$2,298,714	$2,295,784	$2,292,854	$2,289,924	$2,286,994	$2,284,064	$2,281,134	$2,278,204	$2,275,274	$2,272,344	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.72%		3,310	3,305	3,301	3,297	3,293	3,289	3,284	3,280	3,276	3,272	3,268	3,263	39,438
	b. Equity Component Grossed Up For Taxes	6.07%		11,666	11,651	11,636	11,621	11,606	11,592	11,577	11,562	11,547	11,532	11,517	11,503	139,010
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	35,160
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes			100	100	100	100	100	100	100	100	100	100	100	100	1,200
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$18,006	$17,986	$17,967	$17,948	$17,929	$17,911	$17,891	$17,872	$17,853	$17,834	$17,815	$17,796	214,808
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			18,006	17,986	17,967	17,948	17,929	17,911	17,891	17,872	17,853	17,834	17,815	17,796	214,808
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)			16,725	16,706	16,689	16,671	16,653	16,637	16,618	16,600	16,583	16,565	16,547	16,530	199,524
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$16,725	$16,706	$16,689	$16,671	$16,653	$16,637	$16,618	$16,600	$16,583	$16,565	$16,547	$16,530	$199,524

Notes:
(A) N/A
(B) Line 6 x 7.80% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.52% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology.
(C) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets in-service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 Rate Case Order PSC-2010-0131-FOF-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets in-service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2020 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2021 - December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Intermediate (Project 4.3)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	
3	Less: Accumulated Depreciation		(91,686)	(92,211)	(92,736)	(93,261)	(93,786)	(94,311)	(94,836)	(95,361)	(95,886)	(96,411)	(96,936)	(97,461)	(97,986)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+ 3 + 4)		$198,611	$198,086	$197,561	$197,036	$196,511	$195,986	$195,461	$194,936	$194,411	$193,886	$193,361	$192,836	$192,311	
6	Average Net Investment			$198,349	$197,824	$197,299	$196,774	$196,249	$195,724	$195,199	$194,674	$194,149	$193,624	$193,099	$192,574	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.72%		285	284	283	283	282	281	280	280	279	278	277	277	3,369
	b. Equity Component Grossed Up For Taxes	6.07%		1,004	1,001	999	996	993	991	988	985	983	980	977	975	11,872
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			525	525	525	525	525	525	525	525	525	525	525	525	6,300
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes			144	144	144	144	144	144	144	144	144	144	144	144	1,728
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$1,958	$1,954	$1,951	$1,948	$1,944	$1,941	$1,937	$1,934	$1,931	$1,927	$1,923	$1,921	23,269
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,958	1,954	1,951	1,948	1,944	1,941	1,937	1,934	1,931	1,927	1,923	1,921	23,269
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)			0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)			1,424	1,421	1,418	1,416	1,413	1,411	1,408	1,406	1,404	1,401	1,398	1,397	16,917
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$1,424	$1,421	$1,418	$1,416	$1,413	$1,411	$1,408	$1,406	$1,404	$1,401	$1,398	$1,397	$16,917

Notes:
(A) N/A
(B) Line 6 x 7.80% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.52% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology.
(C) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets in-service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 Rate Case Order PSC-2010-0131-FOF-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets in-service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2020 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2021 - December 2021

SO2 and NOx EMISSIONS ALLOWANCES - Energy (Project 5)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Working Capital Dr (Cr)															
	a. 0158150 SO_2 Emission Allowance Inventory		$3,221,472	$3,221,195	$3,220,747	$3,219,923	$3,219,242	$3,218,211	$3,218,251	$3,216,516	$3,214,837	$3,213,156	$3,211,507	$3,210,519	$3,209,227	$3,209,227
	b. 0254020 Auctioned SO_2 Allowance		0	0	0	0	0	0	0	0	0	0	0	0	0	0
	c. 0158170 NOx Emission Allowance Inventory		0	0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Total Working Capital		$3,221,472	$3,221,195	$3,220,747	$3,219,923	$3,219,242	$3,218,211	$3,218,251	$3,216,516	$3,214,837	$3,213,156	$3,211,507	$3,210,519	$3,209,227	$3,209,227
3	Average Net Investment			$3,221,333	$3,220,971	$3,220,335	$3,219,583	$3,218,727	$3,218,231	$3,217,384	$3,215,676	$3,213,996	$3,212,331	$3,211,013	$3,209,873	
4	Return on Average Net Working Capital Balance (B)															
	a. Debt Component	1.72%		4,626	4,626	4,625	4,624	4,622	4,622	4,620	4,618	4,616	4,613	4,611	4,610	55,433
	b. Equity Component Grossed Up For Taxes	6.07%		16,306	16,305	16,301	16,298	16,293	16,291	16,286	16,278	16,269	16,261	16,254	16,248	195,390
5	Total Return Component (C)			$20,932	$20,931	$20,926	$20,922	$20,915	$20,913	$20,906	$20,896	$20,885	$20,874	$20,865	$20,858	250,823
6	Expense Dr (Cr)															
	a. 0509030 SO_2 Allowance Expense			$276	$448	$824	$681	$1,031	($40)	$ 1,735	$ 1,680	$1,680	$1,649	$988	$1,292	12,245
	b. 0407426 Amortization Expense			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. 0509212 NOx Allowance Expense			0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
7	Net Expense (D)			276	448	824	681	1,031	(40)	1,735	1,680	1,680	1,649	988	1,292	12,245
8	Total System Recoverable Expenses (Lines 5 + 7)			$21,208	$21,379	$21,750	$21,603	$21,946	$20,873	$22,641	$22,576	$22,565	$22,523	$21,853	$22,150	263,068
	a. Recoverable Costs Allocated to Energy			21,208	21,379	21,750	21,603	21,946	20,873	22,641	22,576	22,565	22,523	21,853	22,150	263,068
	b. Recoverable Costs Allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor			0.93240	0.97190	0.97100	0.95630	0.91870	0.90580	0.90872	0.90773	0.92667	0.94357	0.95226	0.97002	
10	Demand Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Retail Energy-Related Recoverable Costs (E)			$19,775	$20,778	$21,119	$20,659	$20,162	$18,907	$20,574	$20,493	$20,911	$21,253	$20,810	$21,486	246,925
12	Retail Demand-Related Recoverable Costs (F)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Total Jurisdictional Recoverable Costs (Lines 11 + 12)			$ 19,775	$ 20,778	$ 21,119	$ 20,659	$ 20,162	$ 18,907	$ 20,574	$ 20,493	$ 20,911	$ 21,253	$ 20,810	$ 21,486	$ 246,925

Notes:
(A) N/A
(B) Line 6 x 7.80% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.52% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology.
(C) Line 5 is reported on Capital Schedule
(D) Line 7 is reported on O&M Schedule
(E) Line 8a x Line 9
(F) Line 8b x Line 10

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2021 - December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Phase II Cooling Water Intake 316(b) - Base (Project 6)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$95,730	$142,783	$85,221	$145,772	$264,254	$189,996	$221,208	$210,935	$119,102	$567,612	$114,612	$16,382	$2,173,607
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	12,374,053	114,612	16,382	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$0	0	0	0	0	0	0	0	0	0	12,374,053	12,488,665	12,505,047	
3	Less: Accumulated Depreciation		$0	0	0	0	0	0	0	0	0	0	(15,323)	(30,788)	(46,273)	
4	CWIP - Non-Interest Bearing		$10,331,440	10,427,170	10,569,953	10,655,174	10,800,946	11,065,200	11,255,195	11,476,404	11,687,339	11,806,441	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$10,331,440	$10,427,170	$10,569,953	$10,655,174	$10,800,946	$11,065,200	$11,255,195	$11,476,404	$11,687,339	$11,806,441	$12,358,730	$12,457,877	$12,458,774	
6	Average Net Investment			$10,379,305	$10,498,561	$10,612,563	$10,728,060	$10,933,073	$11,160,197	$11,365,799	$11,581,871	$11,746,890	$12,082,585	$12,408,303	$12,458,325	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.72%		14,906	15,077	15,241	15,407	15,701	16,027	16,322	16,633	16,870	17,352	17,820	17,891	195,247
	b. Equity Component Grossed Up For Taxes	6.07%		52,540	53,144	53,721	54,306	55,343	56,493	57,534	58,628	59,463	61,162	62,811	63,064	688,209
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	1.4860%		0	0	0	0	0	0	0	0	0	15,323	15,465	15,485	46,273
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.000507		0	0	0	0	0	0	0	0	0	522	527	528	1,577
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$67,446	$68,221	$68,962	$69,713	$71,044	$72,520	$73,856	$75,261	$76,333	$94,359	$96,623	$96,968	931,306
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$67,446	$68,221	$68,962	$69,713	$71,044	$72,520	$73,856	$75,261	$76,333	$94,359	$96,623	$96,968	931,306
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)			62,647	63,367	64,055	64,753	65,989	67,360	68,601	69,906	70,902	87,645	89,748	90,069	865,044
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$62,647	$63,367	$64,055	$64,753	$65,989	$67,360	$68,601	$69,906	$70,902	$87,645	$89,748	$90,069	$865,044

Notes:
(A) N/A
(B) Line 6 x 7.80% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.52% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology.
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2020 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2021 - December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Phase II Cooling Water Intake 316(b) - Base - Bartow (Project 6.1)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation	$0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing	$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
6	Average Net Investment		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
7	Return on Average Net Investment (B)														
	a. Debt Component 1.72%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Equity Component Grossed Up For Taxes 6.07%		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation (C) 1.4860%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.000507		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
10	Energy Jurisdictional Factor		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)		0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:
(A) N/A
(B) Line 6 x 7.80% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.52% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology.
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2020 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2021 - December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Phase II Cooling Water Intake 316(b) - Intermediate - Anclote (Project 6.2)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+ 3 + 4)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
6	Average Net Investment			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.72%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Equity Component Grossed Up For Taxes	6.07%		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.005960			0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)			0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)			0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:
(A) N/A
(B) Line 6 x 7.80% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.52% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology.
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2020 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2021 - December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Peaking (Project 7.2 - CT Emission Monitoring Systems)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$1,293,144	$1,293,144	$1,293,144	$1,293,144	$1,293,144	$1,293,144	$1,293,144	$1,293,144	$1,293,144	$1,293,144	$1,293,144	$1,293,144	$1,293,144	
3	Less: Accumulated Depreciation		(358,483)	(360,654)	(362,825)	(364,996)	(367,167)	(369,338)	(371,509)	(373,680)	(375,851)	(378,022)	(380,193)	(382,364)	(384,535)	
3a	Regulatory Asset Balance (G)		87,234	78,511	69,787	61,064	52,341	43,617	34,894	26,170	17,447	8,723	0	0	0	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$1,021,895	$1,011,001	$1,000,106	$989,212	$978,318	$967,423	$956,529	$945,634	$934,740	$923,845	$912,951	$910,780	$908,609	
6	Average Net Investment			$1,016,448	$1,005,554	$994,659	$983,765	$972,870	$961,976	$951,082	$940,187	$929,293	$918,398	$911,866	$909,695	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.72%		1,459	1,443	1,428	1,412	1,398	1,381	1,366	1,350	1,334	1,319	1,309	1,307	16,506
	b. Equity Component Grossed Up For Taxes	6.07%		5,146	5,090	5,034	4,979	4,924	4,869	4,814	4,758	4,704	4,650	4,616	4,604	58,188
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			2,171	2,171	2,171	2,171	2,171	2,171	2,171	2,171	2,171	2,171	2,171	2,171	26,052
	b. Amortization (G)			8,723	8,723	8,723	8,723	8,723	8,723	8,723	8,723	8,723	8,723	0	0	87,234
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes			910	910	910	910	910	910	910	910	910	910	910	910	10,920
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$18,409	$18,337	$18,266	$18,195	$18,126	$18,054	$17,984	$17,912	$17,842	$17,773	$9,006	$8,992	198,900
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			18,409	18,337	18,266	18,195	18,126	18,054	17,984	17,912	17,842	17,773	9,006	8,992	198,900
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Peaking)			0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)			17,659	17,590	17,522	17,454	17,388	17,319	17,251	17,182	17,115	17,049	8,639	8,625	190,793
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$17,659	$17,590	$17,522	$17,454	$17,388	$17,319	$17,251	$17,182	$17,115	$17,049	$8,639	$8,625	$190,793

Notes:
(A) N/A
(B) Line 6 x 7.80% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.52% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology.
(C) Depreciation calculated in CAIR CTs section of Capital Program Detail file only on assets in-service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 Rate Case Order PSC-2010-0131-FOF-EI.
(D) Property tax calculated in CAIR CTs section of Capital Program Detail file only on assets in-service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2020 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11
(G) Investment amortized over one year as approved in Order No. PSC-2019-0500-FOF-EI.

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2021 - December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Base (Project 7.4 - Crystal River)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$86,699,701	86,699,701	86,699,701	86,699,701	86,699,701	86,699,701	86,699,701	86,699,701	86,699,701	86,699,701	86,699,701	86,699,701	86,699,701	
3	Less: Accumulated Depreciation		($2,893,910)	(3,003,993)	(3,114,076)	(3,224,159)	(3,334,242)	(3,444,325)	(3,554,408)	(3,664,491)	(3,774,574)	(3,884,657)	(3,994,740)	(4,104,823)	(4,214,906)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$83,805,791	$83,695,708	$83,585,625	$83,475,542	$83,365,459	$83,255,376	$83,145,293	$83,035,210	$82,925,127	$82,815,044	$82,704,961	$82,594,878	$82,484,795	
6	Average Net Investment			$83,750,750	$83,640,667	$83,530,584	$83,420,501	$83,310,418	$83,200,335	$83,090,252	$82,980,169	$82,870,086	$82,760,003	$82,649,920	$82,539,837	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.72%		120,274	120,116	119,958	119,800	119,642	119,483	119,326	119,168	119,010	118,852	118,695	118,535	1,432,859
	b. Equity Component Grossed Up For Taxes	6.07%		423,948	423,392	422,834	422,277	421,720	421,161	420,605	420,047	419,490	418,933	418,376	417,819	5,050,602
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			110,083	110,083	110,083	110,083	110,083	110,083	110,083	110,083	110,083	110,083	110,083	110,083	1,320,996
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes			3,661	3,661	3,661	3,661	3,661	3,661	3,661	3,661	3,661	3,661	3,661	3,661	43,932
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$657,966	$657,252	$656,536	$655,821	$655,106	$654,388	$653,675	$652,959	$652,244	$651,529	$650,815	$650,098	7,848,389
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			657,966	657,252	656,536	655,821	655,106	654,388	653,675	652,959	652,244	651,529	650,815	650,098	7,848,389
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)			611,152	610,489	609,823	609,159	608,495	607,828	607,166	606,501	605,837	605,173	604,510	603,844	7,289,976
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$611,152	$610,489	$609,823	$609,159	$608,495	$607,828	$607,166	$606,501	$605,837	$605,173	$604,510	$603,844	$7,289,976

Notes:
(A) N/A
(B) Line 6 x 7.80% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.52% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology.
(C) Depreciation calculated in CAIR Crystal River section of Capital Program Detail file only on assets in-service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 Rate Case Order PSC-2010-0131-FOF-EI.
(D) Property taxes calculated in CAIR Crystal River section of Capital Program Detail file only on assets in-service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2020 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 20210007-EI
Duke Energy Florida
Witness: G. P. Dean
Exh. No. __ (GPD-3)
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DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2021 - December 2021

Schedule of Amortization and Return
For Project: CAIR/CAMR - Energy (Project 7.4 - Reagents and By-Products)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Working Capital Dr (Cr)															
	a. 0154401 Ammonia Inventory		$1,085,249	$1,092,213	$1,158,834	$1,260,560	$1,360,290	$1,521,548	$1,666,264	$1,343,285	$1,343,285	$1,343,285	$1,343,285	$1,343,285	$1,343,285	$1,343,285
	b. 0154200 Limestone Inventory		$1,565,630	1,630,427	1,595,494	1,654,177	1,729,944	1,805,177	1,859,589	1,712,468	1,712,468	1,712,468	1,712,468	1,712,468	1,712,468	1,712,468
2	Total Working Capital		$2,650,879	$2,722,640	$2,754,327	$2,914,737	$3,090,233	$3,326,726	$3,525,853	$3,055,753	$3,055,753	$3,055,753	$3,055,753	$3,055,753	$3,055,753	3,055,753
3	Average Net Investment			2,686,759	2,738,484	2,834,532	3,002,485	3,208,479	3,426,289	3,290,803	3,055,753	3,055,753	3,055,753	3,055,753	3,055,753	
4	Return on Average Net Working Capital Balance (A)															
	a. Debt Component	1.72%		3,858	3,933	4,071	4,312	4,608	4,921	4,726	4,388	4,388	4,388	4,388	4,388	$52,370
	b. Equity Component Grossed Up For Taxes	6.07%		13,600	13,862	14,348	15,199	16,241	17,344	16,658	15,468	15,468	15,468	15,468	15,468	184,595
5	Total Return Component (B)			17,459	17,795	18,419	19,511	20,849	22,264	21,384	19,857	19,857	19,857	19,857	19,857	236,965
6	Expense Dr (Cr)															
	a. 0502030 Ammonia Expense			70,708	177,922	155,237	243,072	288,539	287,344	226,500	246,100	193,000	177,800	25,600	25,600	2,117,423
	b. 0502040 Limestone Expense			172,327	279,823	294,260	464,173	388,393	522,186	340,955	329,065	340,714	325,518	322,756	354,858	4,135,027
	c. 0502050 Dibasic Acid Expense			0	0	0	0	0	0	1,700	1,900	1,500	1,400	200	200	6,900
	d. 0502070 Gypsum Disposal/Sale			(68,152)	(146,981)	(294,070)	(266,005)	(306,466)	(503,649)	(315,302)	(304,850)	(315,985)	(301,779)	(299,526)	(329,702)	(3,452,468)
	e. 0502040 Hydrated Lime Expense			120,207	189,147	193,230	307,327	355,741	323,803	190,800	207,200	162,700	150,000	21,650	21,650	2,243,454
	f. 0502300 Caustic Expense (F)			0	0	(83,375)	0	0	0	0	0	0	0	0	0	(83,375)
7	Net Expense (C)			295,089	499,910	265,281	748,567	726,207	629,684	444,653	479,415	381,929	352,939	70,680	72,606	4,966,961
8	Total System Recoverable Expenses (Lines 5 + 7)			$312,548	$517,705	$283,700	$768,077	$747,056	$651,948	$466,037	$499,272	$401,786	$372,795	$90,537	$92,463	5,203,925
	a. Recoverable Costs Allocated to Energy			312,548	517,705	283,700	768,077	747,056	651,948	466,037	499,272	401,786	372,795	90,537	92,463	5,203,925
	b. Recoverable Costs Allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor			0.93240	0.97190	0.97100	0.95630	0.91870	0.90580	0.90872	0.90773	0.92667	0.94357	0.95226	0.97002	
10	Demand Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Retail Energy-Related Recoverable Costs (D)			291,420	503,158	275,473	734,512	686,320	590,535	423,496	453,206	372,321	351,760	86,215	89,691	4,858,107
12	Retail Demand-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Total Jurisdictional Recoverable Costs (Lines 11 + 12)			$ 291,420	$ 503,158	$ 275,473	$ 734,512	$ 686,320	$ 590,535	$ 423,496	$ 453,206	$ 372,321	$ 351,760	$ 86,215	$ 89,691	$ 4,858,107

Notes:
(A) Line 6 x 7.80% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.52% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology.
(B) Line 5 is reported on Capital Schedule
(C) Line 7 is reported on O&M Schedule
(D) Line 8a x Line 9
(E) Line 8b x Line 10
(F) March 2021 includes a credit to revise prior period billing invoice; the credit includes applicable commercial paper interest.

Docket No. 20210007-EI
Duke Energy Florida
Witness: G. P. Dean
Exh. No. __ (GPD-3)

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2021 - December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: SEA TURTLE - COASTAL STREET LIGHTING - (Project 9)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$11,324	11,324	11,324	11,324	11,324	11,324	11,324	11,324	11,324	11,324	11,324	11,324	11,324	
3	Less: Accumulated Depreciation		(4,394)	(4,423)	(4,452)	(4,481)	(4,510)	(4,539)	(4,568)	(4,597)	(4,626)	(4,655)	(4,684)	(4,713)	(4,742)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$6,930	$6,901	$6,872	$6,843	$6,814	$6,785	$6,756	$6,727	$6,698	$6,669	$6,640	$6,611	$6,582	
6	Average Net Investment			$6,916	$6,887	$6,858	$6,829	$6,800	$6,771	$6,742	$6,713	$6,684	$6,655	$6,626	$6,597	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.72%		10	10	10	10	10	10	10	10	10	10	10	9	119
	b. Equity Component Grossed Up For Taxes	6.07%		35	35	35	35	34	34	34	34	34	34	34	33	411
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C) 3.0658%			29	29	29	29	29	29	29	29	29	29	29	29	348
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.007205			7	7	7	7	7	7	7	7	7	7	7	7	84
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$81	$81	$81	$81	$80	$80	$80	$80	$80	$80	$80	$78	962
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$81	$81	$81	$81	$80	$80	$80	$80	$80	$80	$80	$78	962
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - (Distribution)			0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)			81	81	81	81	80	80	80	80	80	80	80	78	958
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$81	$81	$81	$81	$80	$80	$80	$80	$80	$80	$80	$78	$958

Notes:
(A) N/A
(B) Line 6 x 7.80% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.52% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology.
(C) Line 2 x rate x 1/12. Depreciation Rate based on 2010 Rate Case Order PSC-2010-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2020 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 20210007-EI
Duke Energy Florida
Witness: G. P. Dean
Exh. No. __ (GPD-3)

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2021 - December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: UNDERGROUND STORAGE TANKS - Base (Project 10.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	
3	Less: Accumulated Depreciation		(53,104)	(53,400)	(53,696)	(53,992)	(54,288)	(54,584)	(54,880)	(55,176)	(55,472)	(55,768)	(56,064)	(56,360)	(56,656)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$115,837	$115,541	$115,245	$114,949	$114,653	$114,357	$114,061	$113,765	$113,469	$113,173	$112,877	$112,581	$112,285	
6	Average Net Investment			$115,689	$115,393	$115,097	$114,801	$114,505	$114,209	$113,913	$113,617	$113,321	$113,025	$112,729	$112,433	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.72%		166	166	165	165	164	164	164	163	163	162	162	161	1,965
	b. Equity Component Grossed Up For Taxes	6.07%		586	584	583	581	580	578	577	575	574	572	571	569	6,930
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	2.1000%		296	296	296	296	296	296	296	296	296	296	296	296	3,552
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.000507		7	7	7	7	7	7	7	7	7	7	7	7	84
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$1,055	$1,053	$1,051	$1,049	$1,047	$1,045	$1,044	$1,041	$1,040	$1,037	$1,036	$1,033	12,531
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$1,055	$1,053	$1,051	$1,049	$1,047	$1,045	$1,044	$1,041	$1,040	$1,037	$1,036	$1,033	12,531
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)			980	978	976	974	973	971	970	967	966	963	962	960	11,639
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$980	$978	$976	$974	$973	$971	$970	$967	$966	$963	$962	$960	$11,639

Notes:
(A) N/A
(B) Line 6 x 7.80% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.52% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology.
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2020 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2021 - December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: UNDERGROUND STORAGE TANKS - Intermediate (10.2)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	$76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	
3	Less: Accumulated Depreciation	(33,965)	(34,168)	(34,371)	(34,574)	(34,777)	(34,980)	(35,183)	(35,386)	(35,589)	(35,792)	(35,995)	(36,198)	(36,401)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$42,041	$41,838	$41,635	$41,432	$41,229	$41,026	$40,823	$40,620	$40,417	$40,214	$40,011	$39,808	$39,605	
6	Average Net Investment		$41,940	$41,737	$41,534	$41,331	$41,128	$40,925	$40,722	$40,519	$40,316	$40,113	$39,910	$39,707	
7	Return on Average Net Investment (B)														
	a. Debt Component 1.72%		60	60	60	59	59	59	58	58	58	58	57	57	703
	b. Equity Component Grossed Up For Taxes 6.07%		212	211	210	209	208	207	206	205	204	203	202	201	2,478
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation (C) 3.2000%		203	203	203	203	203	203	203	203	203	203	203	203	2,436
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.000507		3	3	3	3	3	3	3	3	3	3	3	3	36
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		$478	$477	$476	$474	$473	$472	$470	$469	$468	$467	$465	$464	5,653
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		$478	$477	$476	$474	$473	$472	$470	$469	$468	$467	$465	$464	5,653
10	Energy Jurisdictional Factor		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)		0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
12	Retail Energy-Related Recoverable Costs (E)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)		348	347	346	345	344	343	342	341	340	340	338	337	4,110
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$348	$347	$346	$345	$344	$343	$342	$341	$340	$340	$338	$337	$4,110

Notes:
(A) N/A
(B) Line 6 x 7.80% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.52% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology.
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2020 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2021 - December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Effluent Limitation Guidelines CRN - Energy (Project 15.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$2,612,979	2,612,979	2,612,979	2,612,979	2,612,979	2,612,979	2,612,979	2,612,979	2,612,979	2,612,979	2,612,979	2,612,979	2,612,979	
3	Less: Accumulated Depreciation		(37,787)	(43,165)	(48,543)	(53,921)	(59,299)	(64,677)	(70,055)	(75,433)	(80,811)	(86,189)	(91,567)	(96,945)	(102,323)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$2,575,192	$2,569,814	$2,564,436	$2,559,058	$2,553,680	$2,548,302	$2,542,924	$2,537,546	$2,532,168	$2,526,790	$2,521,412	$2,516,034	$2,510,656	
6	Average Net Investment			$2,572,503	$2,567,125	$2,561,747	$2,556,369	$2,550,991	$2,545,613	$2,540,235	$2,534,857	$2,529,479	$2,524,101	$2,518,723	$2,513,345	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.72%		3,694	3,687	3,679	3,671	3,663	3,656	3,648	3,640	3,633	3,625	3,617	3,609	43,822
	b. Equity Component Grossed Up For Taxes	6.07%		13,022	12,995	12,968	12,940	12,913	12,886	12,859	12,832	12,804	12,777	12,750	12,723	154,469
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C) 2.4700%			5,378	5,378	5,378	5,378	5,378	5,378	5,378	5,378	5,378	5,378	5,378	5,378	64,536
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.000507			110	110	110	110	110	110	110	110	110	110	110	110	1,320
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$22,204	$22,170	$22,135	$22,099	$22,064	$22,030	$21,995	$21,960	$21,925	$21,890	$21,855	$21,820	264,147
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$22,204	$22,170	$22,135	$22,099	$22,064	$22,030	$21,995	$21,960	$21,925	$21,890	$21,855	$21,820	264,147
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)			$20,624	$20,593	$20,560	$20,527	$20,494	$20,463	$20,430	$20,398	$20,365	$20,333	$20,300	$20,268	245,355
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$20,624	$20,593	$20,560	$20,527	$20,494	$20,463	$20,430	$20,398	$20,365	$20,333	$20,300	$20,268	$245,355

Notes:
(A) N/A
(B) Line 6 x 7.80% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.52% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology.
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2020 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 20210007-EI
Duke Energy Florida
Witness: G. P. Dean
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DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2021 - December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: NPDES - Intermediate (Project 16)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	
3	Less: Accumulated Depreciation		(2,572,638)	(2,608,310)	(2,643,982)	(2,679,654)	(2,715,326)	(2,750,998)	(2,786,670)	(2,822,342)	(2,858,014)	(2,893,686)	(2,929,358)	(2,965,030)	(3,000,702)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$10,269,232	$10,233,560	$10,197,888	$10,162,216	$10,126,544	$10,090,872	$10,055,200	$10,019,528	$9,983,856	$9,948,184	$9,912,512	$9,876,840	$9,841,168	
6	Average Net Investment			$10,251,396	$10,215,724	$10,180,052	$10,144,380	$10,108,708	$10,073,036	$10,037,364	$10,001,692	$9,966,020	$9,930,348	$9,894,676	$9,859,004	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.72%		14,722	14,671	14,620	14,568	14,517	14,466	14,415	14,363	14,312	14,261	14,210	14,159	173,284
	b. Equity Component Grossed Up For Taxes	6.07%		51,893	51,712	51,532	51,351	51,171	50,990	50,809	50,629	50,448	50,268	50,087	49,907	610,797
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	3.3333%		35,672	35,672	35,672	35,672	35,672	35,672	35,672	35,672	35,672	35,672	35,672	35,672	428,064
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008120		8,690	8,690	8,690	8,690	8,690	8,690	8,690	8,690	8,690	8,690	8,690	8,690	104,280
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$110,977	$110,745	$110,514	$110,281	$110,050	$109,818	$109,586	$109,354	$109,122	$108,891	$108,659	$108,428	1,316,425
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$110,977	$110,745	$110,514	$110,281	$110,050	$109,818	$109,586	$109,354	$109,122	$108,891	$108,659	$108,428	1,316,425
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)			0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)			80,684	80,515	80,347	80,178	80,010	79,841	79,672	79,504	79,335	79,167	78,998	78,830	957,080
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$80,684	$80,515	$80,347	$80,178	$80,010	$79,841	$79,672	$79,504	$79,335	$79,167	$78,998	$78,830	$957,080

Notes:
(A) N/A
(B) Line 6 x 7.80% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.52% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology.
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2020 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2021 - December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: MERCURY & AIR TOXIC STANDARDS (MATS) - CRYSTAL RIVER UNITS 4 & 5 - Energy (Project 17)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	
3	Less: Accumulated Depreciation		(424,949)	(431,531)	(438,113)	(444,695)	(451,277)	(457,859)	(464,441)	(471,023)	(477,605)	(484,187)	(490,769)	(497,351)	(503,933)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$3,265,238	$3,258,656	$3,252,074	$3,245,492	$3,238,910	$3,232,328	$3,225,746	$3,219,164	$3,212,582	$3,206,000	$3,199,418	$3,192,836	$3,186,254	
6	Average Net Investment			$3,261,947	$3,255,365	$3,248,783	$3,242,201	$3,235,619	$3,229,037	$3,222,455	$3,215,873	$3,209,291	$3,202,709	$3,196,127	$3,189,545	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.72%		4,684	4,675	4,666	4,656	4,647	4,637	4,628	4,618	4,609	4,599	4,590	4,581	55,590
	b. Equity Component Grossed Up For Taxes	6.07%		16,512	16,479	16,445	16,412	16,379	16,345	16,312	16,279	16,246	16,212	16,179	16,146	195,946
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C) Blended			6,582	6,582	6,582	6,582	6,582	6,582	6,582	6,582	6,582	6,582	6,582	6,582	78,984
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.000507			156	156	156	156	156	156	156	156	156	156	156	156	1,872
	e. Other (E)			(597)	(597)	(597)	(597)	(597)	(597)	(597)	(597)	(597)	(597)	(597)	(597)	(7,160)
9	Total System Recoverable Expenses (Lines 7 + 8)			$27,337	$27,295	$27,252	$27,209	$27,167	$27,123	$27,081	$27,038	$26,996	$26,952	$26,910	$26,868	325,232
	a. Recoverable Costs Allocated to Energy			27,337	27,295	27,252	27,209	27,167	27,123	27,081	27,038	26,996	26,952	26,910	26,868	325,232
	b. Recoverable Costs Allocated to Demand			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
10	Energy Jurisdictional Factor			0.93240	0.97190	0.97100	0.95630	0.91870	0.90580	0.90872	0.90773	0.92667	0.94357	0.95226	0.97002	
11	Demand Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
12	Retail Energy-Related Recoverable Costs (F)			$25,489	$26,528	$26,462	$26,020	$24,959	$24,568	$24,609	$24,544	$25,017	$25,432	$25,626	$26,063	$305,317
13	Retail Demand-Related Recoverable Costs (G)			0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$25,489	$26,528	$26,462	$26,020	$24,959	$24,568	$24,609	$24,544	$25,017	$25,432	$25,626	$26,063	$305,317

Notes:
(A) N/A
(B) Line 6 x 7.80% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.52% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology.
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2020 Effective Tax Rate on original cost.
(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 19990007-EI, Order No. PSC-1999-2513-FOF-EI.
(F) Line 9a x Line 10
(G) Line 9b x Line 11

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2021 - December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: MERCURY & AIR TOXIC STANDARDS (MATS) - ANCLOTE GAS CONVERSION - Energy (Project 17.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other - AFUDC (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$133,918,267	133,918,267	133,918,267	133,918,267	133,918,267	133,918,267	133,918,267	133,918,267	133,918,267	133,918,267	133,918,267	133,918,267	133,918,267	
3	Less: Accumulated Depreciation		(20,366,566)	(20,608,980)	(20,851,394)	(21,093,808)	(21,336,222)	(21,578,636)	(21,821,050)	(22,063,464)	(22,305,878)	(22,548,292)	(22,790,706)	(23,033,120)	(23,275,534)	
4	CWIP - AFUDC Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$113,551,701	$113,309,287	$113,066,873	$112,824,459	$112,582,045	$112,339,631	$112,097,217	$111,854,803	$111,612,389	$111,369,975	$111,127,561	$110,885,147	$110,642,733	
6	Average Net Investment			$113,430,494	$113,188,080	$112,945,666	$112,703,252	$112,460,838	$112,218,424	$111,976,010	$111,733,596	$111,491,182	$111,248,768	$111,006,354	$110,763,940	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.72%		162,898	162,550	162,201	161,853	161,505	161,157	160,809	160,461	160,113	159,765	159,416	159,068	1,931,796
	b. Equity Component Grossed Up For Taxes	6.07%		574,188	572,961	571,734	570,507	569,279	568,052	566,825	565,598	564,371	563,144	561,917	560,690	6,809,266
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C) 2.1722%			242,414	242,414	242,414	242,414	242,414	242,414	242,414	242,414	242,414	242,414	242,414	242,414	2,908,968
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.005960			66,513	66,513	66,513	66,513	66,513	66,513	66,513	66,513	66,513	66,513	66,513	66,513	798,156
	e. Other (E)			(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(177,534)
9	Total System Recoverable Expenses (Lines 7 + 8)			$1,031,219	$1,029,644	$1,028,068	$1,026,493	$1,024,917	$1,023,342	$1,021,767	$1,020,192	$1,018,617	$1,017,042	$1,015,466	$1,013,891	12,270,652
	a. Recoverable Costs Allocated to Energy			1,031,219	1,029,644	1,028,068	1,026,493	1,024,917	1,023,342	1,021,767	1,020,192	1,018,617	1,017,042	1,015,466	1,013,891	12,270,652
	b. Recoverable Costs Allocated to Demand			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
10	Energy Jurisdictional Factor			0.93240	0.97190	0.97100	0.95630	0.91870	0.90580	0.90872	0.90773	0.92667	0.94357	0.95226	0.97002	
11	Demand Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
12	Retail Energy-Related Recoverable Costs (F)			$961,508	$1,000,711	$998,254	$981,635	$941,591	$926,943	$928,497	$926,063	$943,917	$959,653	$966,991	$983,492	$11,519,255
13	Retail Demand-Related Recoverable Costs (G)			0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$961,508	$1,000,711	$998,254	$981,635	$941,591	$926,943	$928,497	$926,063	$943,917	$959,653	$966,991	$983,492	$11,519,255

Notes:
(A) N/A
(B) Line 6 x 7.80% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.52% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology.
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2020 Effective Tax Rate on original cost.
(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 19990007-EI, Order No. PSC-1999-2513-FOF-EI.
(F) Line 9a x Line 10
(G) Line 9b x Line 11

Docket No. 20210007-EI
Duke Energy Florida
Witness: G. P. Dean
Exh. No. __ (GPD-3)
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DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2021 - December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: COAL COMBUSTION RESIDUAL (CCR) RULE - Base (Project 18)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$85,075	$137,082	$524,961	$445,463	$351,992	$130,463	$50,000	$50,000	$0	$0	$0	$0	$1,775,036
	b. Clearings to Plant			0	0	0	0	0	0	0	3,874,267	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$446,090	446,090	446,090	446,090	446,090	446,090	446,090	446,090	4,320,358	4,320,358	4,320,358	4,320,358	4,320,358	
3	Less: Accumulated Depreciation		(29,288)	(30,094)	(30,900)	(31,706)	(32,512)	(33,318)	(34,124)	(34,930)	(42,741)	(50,552)	(58,363)	(66,174)	(73,985)	
4	CWIP - Non-Interest Bearing		2,099,232	2,184,307	2,321,389	2,846,350	3,291,813	3,643,805	3,774,267	3,824,267	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$2,516,034	$2,600,303	$2,736,579	$3,260,734	$3,705,391	$4,056,577	$4,186,234	$4,235,428	$4,277,617	$4,269,806	$4,261,995	$4,254,184	$4,246,373	
6	Average Net Investment			$2,558,168	$2,668,441	$2,998,656	$3,483,062	$3,880,984	$4,121,405	$4,210,831	$4,256,522	$4,273,711	$4,265,900	$4,258,089	$4,250,278	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.72%		3,674	3,832	4,306	5,002	5,573	5,919	6,047	6,113	6,137	6,126	6,115	6,104	64,948
	b. Equity Component Grossed Up For Taxes	6.07%		12,950	13,508	15,179	17,631	19,646	20,863	21,315	21,547	21,634	21,594	21,555	21,515	228,937
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C) 2.1695%			806	806	806	806	806	806	806	7,811	7,811	7,811	7,811	7,811	44,697
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.000507			19	19	19	19	19	19	19	182	182	182	182	182	1,043
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$17,449	$18,165	$20,310	$23,458	$26,044	$27,607	$28,187	$35,653	$35,764	$35,713	$35,663	$35,612	339,625
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			17,449	18,165	20,310	23,458	26,044	27,607	28,187	35,653	35,764	35,713	35,663	35,612	339,625
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)			16,208	16,873	18,865	21,789	24,191	25,643	26,181	33,116	33,219	33,172	33,126	33,078	315,461
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$16,208	$16,873	$18,865	$21,789	$24,191	$25,643	$26,181	$33,116	$33,219	$33,172	$33,126	$33,078	$315,461

Notes:
(A) N/A
(B) Line 6 x 7.80% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.52% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology.
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2020 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2021 - December 2021

Capital Structure and Cost Rates

		(1) Jurisdictional Rate Base Adjusted Retail ($000s)	(2) Cap Ratio	(3) Cost Rate	(4) Weighted Cost	(5) Revenue Requirement Rate	(6) Monthly Revenue Requirement Rate
1	Common Equity	$ 6,564,170	43.08%	10.50%	4.523%	5.99%	0.4992%
2	Long Term Debt	5,970,469	39.18%	4.22%	1.655%	1.66%	0.1383%
3	Short Term Debt	141,506	0.93%	1.10%	0.010%	0.01%	0.0008%
4	Cust Dep Active	181,717	1.19%	2.36%	0.028%	0.03%	0.0025%
5	Cust Dep Inactive	1,883	0.01%			0.00%	0.0000%
6	Invest Tax Cr	176,535	1.16%	7.51%	0.087%	0.11%	0.0092%
7	Deferred Inc Tax	2,202,583	14.45%			0.00%	0.0000%
8	**Total**	**$ 15,238,864**	**100.00%**		**6.304%**	**7.80%**	**0.6500%**

	ITC split between Debt and Equity**		Ratio	Cost Rate	Ratio	Ratio	Deferred Inc Tax	Weighted ITC	After Gross-up
9	Common Equity	6,564,170	52%	10.5%	5.50%	73.2%	0.09%	0.064%	0.084%
10	Preferred Equity	-	0%				0.09%	0.000%	0.000%
11	Long Term Debt	5,970,469	48%	4.22%	2.01%	26.8%	0.09%	0.023%	0.023%
12		12,534,639	100%		7.51%			0.087%	0.108%

	Breakdown of Revenue Requirement Rate of Return between Debt and Equity:	
13	Total Equity Component (Lines 1 and 9)	6.07%
14	Total Debt Component (Lines 2, 3 , 4 , and 11)	1.72%
15	**Total Revenue Requirement Rate of Return**	**7.80%**

Notes:

Effective Tax Rate: 24.522%

Column:

(1) Per Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology
(2) Column (1) / Total Column (1)
(3) Per Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology
(4) Column (2) x Column (3)
(5) For equity components: Column (4) / (1-effective income tax rate/100)
* For debt components: Column (4)
** Line 6 is the pre-tax ITC components from Lines 9 and 11
(6) Column (5) / 12

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Capital Program Detail

January 2021 - December 2021
Actuals for the Period January 2021 - June 2021
Estimates for the Period July 2021 - December 2021
Docket No. 20210007-EI

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BARTOW CTs (Project 4.1b)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	
3	Less: Accumulated Depreciation			(513,597)	(517,282)	(520,967)	(524,652)	(528,337)	(532,022)	(535,707)	(539,392)	(543,077)	(546,762)	(550,447)	(554,132)	(557,817)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$960,204	$956,519	$952,834	$949,149	$945,464	$941,779	$938,094	$934,409	$930,724	$927,039	$923,354	$919,669	$915,984	
6	Average Net Investment				958,362	954,677	950,992	947,307	943,622	939,937	936,252	932,567	928,882	925,197	921,512	917,827	
7	Return on Average Net Investment (A)																
	a. Debt Component		1.72%		1,376	1,371	1,366	1,360	1,355	1,350	1,345	1,339	1,334	1,329	1,323	1,318	16,166
	b. Equity Component Grossed Up For Taxes		6.07%		4,851	4,833	4,814	4,795	4,777	4,758	4,739	4,721	4,702	4,683	4,665	4,646	56,984
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	3.0000%			3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	44,220
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.8120%			997	997	997	997	997	997	997	997	997	997	997	997	11,964
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$10,909	$10,886	$10,862	$10,837	$10,814	$10,790	$10,766	$10,742	$10,718	$10,694	$10,670	$10,646	$129,334
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$10,909	$10,886	$10,862	$10,837	$10,814	$10,790	$10,766	$10,742	$10,718	$10,694	$10,670	$10,646	$129,334

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - INTERCESSION CITY CTs (Project 4.1c)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	
3	Less: Accumulated Depreciation			(1,382,471)	(1,391,610)	(1,400,749)	(1,409,888)	(1,419,027)	(1,428,166)	(1,437,305)	(1,446,444)	(1,455,583)	(1,464,722)	(1,473,861)	(1,483,000)	(1,492,139)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$279,193	$270,054	$260,915	$251,776	$242,637	$233,498	$224,359	$215,220	$206,081	$196,942	$187,803	$178,664	$169,525	
6	Average Net Investment				274,624	265,485	256,346	247,207	238,068	228,929	219,790	210,651	201,512	192,373	183,234	174,095	
7	Return on Average Net Investment (A)																
	a. Debt Component		1.72%		394	381	368	355	342	329	316	303	289	276	263	250	3,866
	b. Equity Component Grossed Up For Taxes		6.07%		1,390	1,344	1,298	1,251	1,205	1,159	1,113	1,066	1,020	974	928	881	13,629
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	6.6000%			9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	109,668
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.6770%			937	937	937	937	937	937	937	937	937	937	937	937	11,244
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$11,860	$11,801	$11,742	$11,682	$11,623	$11,564	$11,505	$11,445	$11,385	$11,326	$11,267	$11,207	$138,407
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$11,860	$11,801	$11,742	$11,682	$11,623	$11,564	$11,505	$11,445	$11,385	$11,326	$11,267	$11,207	$138,407

(A) The allowable return is per the methodology approved in Order No. PSC-2020-0165-PAA-EU.

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - AVON PARK CTs (Project 4.1d)
(in Dollars)

Line	Description	Rate	Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	
3a	Regulatory Asset Balance (B)		53,914	48,523	43,131	37,740	32,349	26,957	21,566	16,174	10,783	5,391	0	0	0	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$53,914	$48,523	$43,132	$37,740	$32,349	$26,957	$21,566	$16,174	$10,783	$5,392	$0	$0	$0	
6	Average Net Investment			51,219	45,827	40,436	35,044	29,653	24,262	18,870	13,479	8,087	2,696	0	0	
7	Return on Average Net Investment (A)															
	a. Debt Component	1.72%		74	66	58	50	43	35	27	19	12	4	0	0	388
	b. Equity Component Grossed Up For Taxes	6.07%		259	232	205	177	150	123	96	68	41	14	0	0	1,365
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	4.8000%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization (B)			5,391	5,391	5,391	5,391	5,391	5,391	5,391	5,391	5,391	5,391	0	0	53,914
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.0000%		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$5,724	$5,689	$5,654	$5,618	$5,584	$5,549	$5,514	$5,478	$5,444	$5,409	$0	$0	$55,667
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$5,724	$5,689	$5,654	$5,618	$5,584	$5,549	$5,514	$5,478	$5,444	$5,409	$0	$0	$55,667

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BAYBORO CTs (Project 4.1e)
(in Dollars)

Line	Description	Rate	Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	
3	Less: Accumulated Depreciation		(286,217)	(288,039)	(289,861)	(291,683)	(293,505)	(295,327)	(297,149)	(298,971)	(300,793)	(302,615)	(304,437)	(306,259)	(308,081)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$444,079	$442,257	$440,435	$438,613	$436,791	$434,969	$433,147	$431,325	$429,503	$427,681	$425,859	$424,037	$422,215	
6	Average Net Investment			443,168	441,346	439,524	437,702	435,880	434,058	432,236	430,414	428,592	426,770	424,948	423,126	
7	Return on Average Net Investment (A)															
	a. Debt Component	1.72%		636	634	631	629	626	623	621	618	616	613	610	608	7,465
	b. Equity Component Grossed Up For Taxes	6.07%		2,243	2,234	2,225	2,216	2,206	2,197	2,188	2,179	2,170	2,160	2,151	2,142	26,311
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.9936%		1,822	1,822	1,822	1,822	1,822	1,822	1,822	1,822	1,822	1,822	1,822	1,822	21,864
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	1.0760%		655	655	655	655	655	655	655	655	655	655	655	655	7,860
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$5,356	$5,345	$5,333	$5,322	$5,309	$5,297	$5,286	$5,274	$5,263	$5,250	$5,238	$5,227	$63,500
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$5,356	$5,345	$5,333	$5,322	$5,309	$5,297	$5,286	$5,274	$5,263	$5,250	$5,238	$5,227	$63,500

(A) The allowable return is per the methodology approved in Order No. PSC-2020-0165-PAA-EU.
(B) Investment amortized over one year as approved in Order No. PSC-2019-0500-FOF-EI.

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - SUWANNEE CTs (Project 4.1f)
(in Dollars)

Line	Description	Rate	Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	
3	Less: Accumulated Depreciation		(460,824)	(463,676)	(466,528)	(469,380)	(472,232)	(475,084)	(477,936)	(480,788)	(483,640)	(486,492)	(489,344)	(492,196)	(495,048)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$576,375	$573,523	$570,671	$567,819	$564,967	$562,115	$559,263	$556,411	$553,559	$550,707	$547,855	$545,003	$542,151	
6	Average Net Investment			574,949	572,097	569,245	566,393	563,541	560,689	557,837	554,985	552,133	549,281	546,429	543,577	
7	Return on Average Net Investment (A)															
	a. Debt Component	1.72%		826	822	817	813	809	805	801	797	793	789	785	781	9,638
	b. Equity Component Grossed Up For Taxes	6.07%		2,910	2,896	2,882	2,867	2,853	2,838	2,824	2,809	2,795	2,780	2,766	2,752	33,972
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.3000%		2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	34,224
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.9290%		803	803	803	803	803	803	803	803	803	803	803	803	9,636
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$7,391	$7,373	$7,354	$7,335	$7,317	$7,298	$7,280	$7,261	$7,243	$7,224	$7,206	$7,188	$87,470
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$7,391	$7,373	$7,354	$7,335	$7,317	$7,298	$7,280	$7,261	$7,243	$7,224	$7,206	$7,188	$87,470

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - DeBARY CTs (Project 4.1g)
(in Dollars)

Line	Description	Rate	Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	
3	Less: Accumulated Depreciation		(1,010,126)	(1,017,963)	(1,025,800)	(1,033,637)	(1,041,474)	(1,049,311)	(1,057,148)	(1,064,985)	(1,072,822)	(1,080,659)	(1,088,496)	(1,096,333)	(1,104,170)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$2,606,778	$2,598,941	$2,591,104	$2,583,267	$2,575,430	$2,567,593	$2,559,756	$2,551,919	$2,544,082	$2,536,245	$2,528,408	$2,520,571	$2,512,734	
6	Average Net Investment			2,602,859	2,595,022	2,587,185	2,579,348	2,571,511	2,563,674	2,555,837	2,548,000	2,540,163	2,532,326	2,524,489	2,516,652	
7	Return on Average Net Investment (A)															
	a. Debt Component	1.72%		3,738	3,727	3,715	3,704	3,693	3,682	3,670	3,659	3,648	3,637	3,625	3,614	44,112
	b. Equity Component Grossed Up For Taxes	6.07%		13,176	13,136	13,096	13,057	13,017	12,977	12,938	12,898	12,858	12,819	12,779	12,739	155,490
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.6000%		7,837	7,837	7,837	7,837	7,837	7,837	7,837	7,837	7,837	7,837	7,837	7,837	94,044
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.7360%		2,218	2,218	2,218	2,218	2,218	2,218	2,218	2,218	2,218	2,218	2,218	2,218	26,616
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$26,969	$26,918	$26,866	$26,816	$26,765	$26,714	$26,663	$26,612	$26,561	$26,511	$26,459	$26,408	$320,262
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$26,969	$26,918	$26,866	$26,816	$26,765	$26,714	$26,663	$26,612	$26,561	$26,511	$26,459	$26,408	$320,262

(A) The allowable return is per the methodology approved in Order No. PSC-2020-0165-PAA-EU.

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - University of Florida (Project 4.1h)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	
3	Less: Accumulated Depreciation			(69,018)	(69,259)	(69,500)	(69,741)	(69,982)	(70,223)	(70,464)	(70,705)	(70,946)	(71,187)	(71,428)	(71,669)	(71,910)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$72,417	$72,176	$71,935	$71,694	$71,453	$71,212	$70,971	$70,730	$70,489	$70,248	$70,007	$69,766	$69,525	
6	Average Net Investment				72,296	72,055	71,814	71,573	71,332	71,091	70,850	70,609	70,368	70,127	69,886	69,645	
7	Return on Average Net Investment (A)																
	a. Debt Component		1.72%		104	103	103	103	102	102	102	101	101	101	100	100	1,222
	b. Equity Component Grossed Up For Taxes		6.07%		366	365	364	362	361	360	359	357	356	355	354	353	4,312
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	2.0482%			241	241	241	241	241	241	241	241	241	241	241	241	2,892
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.8790%			104	104	104	104	104	104	104	104	104	104	104	104	1,248
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$815	$813	$812	$810	$808	$807	$806	$803	$802	$801	$799	$798	$9,674
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$815	$813	$812	$810	$808	$807	$806	$803	$802	$801	$799	$798	$9,674

(A) The allowable return is per the methodology approved in Order No. PSC-2020-0165-PAA-EU.

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 4 & 5 (Project 4.2a)
(in Dollars)

Line	Description	Rate	Rate	Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$2,365,947	2,365,947	2,365,947	2,365,947	2,365,947	2,365,947	2,365,947	2,365,947	2,365,947	2,365,947	2,365,947	2,365,947	2,365,947	
3	Less: Accumulated Depreciation			($59,908)	(62,838)	(65,768)	(68,698)	(71,628)	(74,558)	(77,488)	(80,418)	(83,348)	(86,278)	(89,208)	(92,138)	(95,068)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$2,306,039	$2,303,109	$2,300,179	$2,297,249	$2,294,319	$2,291,389	$2,288,459	$2,285,529	$2,282,599	$2,279,669	$2,276,739	$2,273,809	$2,270,879	
6	Average Net Investment				2,304,574	2,301,644	2,298,714	2,295,784	2,292,854	2,289,924	2,286,994	2,284,064	2,281,134	2,278,204	2,275,274	2,272,344	
7	Return on Average Net Investment (A)																
	a. Debt Component		1.72%		3,310	3,305	3,301	3,297	3,293	3,289	3,284	3,280	3,276	3,272	3,268	3,263	39,438
	b. Equity Component Grossed Up For Taxes		6.07%		11,666	11,651	11,636	11,621	11,606	11,592	11,577	11,562	11,547	11,532	11,517	11,503	139,010
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	1.4860%			2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	35,160
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.0507%			100	100	100	100	100	100	100	100	100	100	100	100	1,200
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$18,006	$17,986	$17,967	$17,948	$17,929	$17,911	$17,891	$17,872	$17,853	$17,834	$17,815	$17,796	$214,808
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$18,006	$17,986	$17,967	$17,948	$17,929	$17,911	$17,891	$17,872	$17,853	$17,834	$17,815	$17,796	$214,808

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Anclote (Project 4.3)
(in Dollars)

Line	Description	Rate	Rate	Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	
3	Less: Accumulated Depreciation			(91,686)	(92,211)	(92,736)	(93,261)	(93,786)	(94,311)	(94,836)	(95,361)	(95,886)	(96,411)	(96,936)	(97,461)	(97,986)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$198,611	$198,086	$197,561	$197,036	$196,511	$195,986	$195,461	$194,936	$194,411	$193,886	$193,361	$192,836	$192,311	
6	Average Net Investment				198,349	197,824	197,299	196,774	196,249	195,724	195,199	194,674	194,149	193,624	193,099	192,574	
7	Return on Average Net Investment (A)																
	a. Debt Component		1.72%		285	284	283	283	282	281	280	280	279	278	277	277	3,369
	b. Equity Component Grossed Up For Taxes		6.07%		1,004	1,001	999	996	993	991	988	985	983	980	977	975	11,872
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	2.1722%			525	525	525	525	525	525	525	525	525	525	525	525	6,300
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.5960%			144	144	144	144	144	144	144	144	144	144	144	144	1,728
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$1,958	$1,954	$1,951	$1,948	$1,944	$1,941	$1,937	$1,934	$1,931	$1,927	$1,923	$1,921	$23,269
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$1,958	$1,954	$1,951	$1,948	$1,944	$1,941	$1,937	$1,934	$1,931	$1,927	$1,923	$1,921	$23,269

(A) The allowable return is per the methodology approved in Order No. PSC-2020-0165-PAA-EU.

For Project: CAIR CTs - AVON PARK (Project 7.2a)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation			0	0	0	0	0	0	0	0	0	0	0	0	0	
3a	Regulatory Asset Balance (B)			87,234	78,511	69,787	61,064	52,341	43,617	34,894	26,170	17,447	8,723	0	0	0	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$87,234	$78,511	$69,787	$61,064	$52,341	$43,617	$34,894	$26,170	$17,447	$8,723	$0	$0	$0	
6	Average Net Investment				82,873	74,149	65,426	56,702	47,979	39,255	30,532	21,809	13,085	4,362	0	0	
7	Return on Average Net Investment (A)																
	a. Debt Component		1.72%		119	106	94	81	69	56	44	31	19	6	0	0	625
	b. Equity Component Grossed Up For Taxes		6.07%		420	375	331	287	243	199	155	110	66	22	0	0	2,208
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	3.0000%			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization (B)				8,723	8,723	8,723	8,723	8,723	8,723	8,723	8,723	8,723	8,723	0	0	87,234
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.0000%			0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$9,262	$9,204	$9,148	$9,091	$9,035	$8,978	$8,922	$8,864	$8,808	$8,751	$0	$0	$90,067
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$9,262	$9,204	$9,148	$9,091	$9,035	$8,978	$8,922	$8,864	$8,808	$8,751	$0	$0	$90,067

For Project: CAIR CTs - BARTOW (Project 7.2b)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	
3	Less: Accumulated Depreciation			(66,745)	(67,103)	(67,461)	(67,819)	(68,177)	(68,535)	(68,893)	(69,251)	(69,609)	(69,967)	(70,325)	(70,683)	(71,041)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$208,602	$208,244	$207,886	$207,528	$207,170	$206,812	$206,454	$206,096	$205,738	$205,380	$205,022	$204,664	$204,306	
6	Average Net Investment				208,423	208,065	207,707	207,349	206,991	206,633	206,275	205,917	205,559	205,201	204,843	204,485	
7	Return on Average Net Investment (A)																
	a. Debt Component		1.72%		299	299	298	298	297	297	296	296	295	295	294	294	3,558
	b. Equity Component Grossed Up For Taxes		6.07%		1,055	1,053	1,051	1,050	1,048	1,046	1,044	1,042	1,041	1,039	1,037	1,035	12,541
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	1.5610%			358	358	358	358	358	358	358	358	358	358	358	358	4,296
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.8120%			186	186	186	186	186	186	186	186	186	186	186	186	2,232
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$1,898	$1,896	$1,893	$1,892	$1,889	$1,887	$1,884	$1,882	$1,880	$1,878	$1,875	$1,873	$22,627
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$1,898	$1,896	$1,893	$1,892	$1,889	$1,887	$1,884	$1,882	$1,880	$1,878	$1,875	$1,873	$22,627

(A) The allowable return is per the methodology approved in Order No. PSC-2020-0165-PAA-EU.
(B) Investment amortized over one year as approved in Order No. PSC-2019-0500-FOF-EI.

For Project: CAIR CTs - BAYBORO (Project 7.2c)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	
3	Less: Accumulated Depreciation			(61,695)	(62,079)	(62,463)	(62,847)	(63,231)	(63,615)	(63,999)	(64,383)	(64,767)	(65,151)	(65,535)	(65,919)	(66,303)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$137,293	$136,909	$136,525	$136,141	$135,757	$135,373	$134,989	$134,605	$134,221	$133,837	$133,453	$133,069	$132,685	
6	Average Net Investment				137,101	136,717	136,333	135,949	135,565	135,181	134,797	134,413	134,029	133,645	133,261	132,877	
7	Return on Average Net Investment (A)																
	a. Debt Component		1.72%		197	196	196	195	195	194	194	193	192	192	191	191	2,326
	b. Equity Component Grossed Up For Taxes		6.07%		694	692	690	688	686	684	682	680	678	677	675	673	8,199
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	2.3149%			384	384	384	384	384	384	384	384	384	384	384	384	4,608
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	1.0760%			178	178	178	178	178	178	178	178	178	178	178	178	2,136
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$1,453	$1,450	$1,448	$1,445	$1,443	$1,440	$1,438	$1,435	$1,432	$1,431	$1,428	$1,426	$17,269
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$1,453	$1,450	$1,448	$1,445	$1,443	$1,440	$1,438	$1,435	$1,432	$1,431	$1,428	$1,426	$17,269

For Project: CAIR CTs - DeBARY (Project 7.2d)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	
3	Less: Accumulated Depreciation			(35,283)	(35,502)	(35,721)	(35,940)	(36,159)	(36,378)	(36,597)	(36,816)	(37,035)	(37,254)	(37,473)	(37,692)	(37,911)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$52,384	$52,165	$51,946	$51,727	$51,508	$51,289	$51,070	$50,851	$50,632	$50,413	$50,194	$49,975	$49,756	
6	Average Net Investment				52,275	52,056	51,837	51,618	51,399	51,180	50,961	50,742	50,523	50,304	50,085	49,866	
7	Return on Average Net Investment (A)																
	a. Debt Component		1.72%		75	75	74	74	74	73	73	73	73	72	72	72	880
	b. Equity Component Grossed Up For Taxes		6.07%		265	264	262	261	260	259	258	257	256	255	254	252	3,103
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	3.0000%			219	219	219	219	219	219	219	219	219	219	219	219	2,628
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.7360%			54	54	54	54	54	54	54	54	54	54	54	54	648
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$613	$612	$609	$608	$607	$605	$604	$603	$602	$600	$599	$597	$7,259
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$613	$612	$609	$608	$607	$605	$604	$603	$602	$600	$599	$597	$7,259

(A) The allowable return is per the methodology approved in Order No. PSC-2020-0165-PAA-EU.

For Project: CAIR CTs - INTERCESSION CITY (Project 7.2f)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	
3	Less: Accumulated Depreciation			(123,343)	(124,130)	(124,917)	(125,704)	(126,491)	(127,278)	(128,065)	(128,852)	(129,639)	(130,426)	(131,213)	(132,000)	(132,787)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$226,241	$225,454	$224,667	$223,880	$223,093	$222,306	$221,519	$220,732	$219,945	$219,158	$218,371	$217,584	$216,797	
6	Average Net Investment				225,847	225,060	224,273	223,486	222,699	221,912	221,125	220,338	219,551	218,764	217,977	217,190	
7	Return on Average Net Investment (A)																
	a. Debt Component		1.72%		324	323	322	321	320	319	318	316	315	314	313	312	3,817
	b. Equity Component Grossed Up For Taxes		6.07%		1,143	1,139	1,135	1,131	1,127	1,123	1,119	1,115	1,111	1,107	1,103	1,099	13,452
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	2.7000%			787	787	787	787	787	787	787	787	787	787	787	787	9,444
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.6770%			197	197	197	197	197	197	197	197	197	197	197	197	2,364
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$2,451	$2,446	$2,441	$2,436	$2,431	$2,426	$2,421	$2,415	$2,410	$2,405	$2,400	$2,395	$29,077
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$2,451	$2,446	$2,441	$2,436	$2,431	$2,426	$2,421	$2,415	$2,410	$2,405	$2,400	$2,395	$29,077

For Project: CAIR CTs - SUWANNEE (Project 7.2h)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	
3	Less: Accumulated Depreciation			($71,418)	(71,841)	(72,264)	(72,687)	(73,110)	(73,533)	(73,956)	(74,379)	(74,802)	(75,225)	(75,648)	(76,071)	(76,494)	
4	CWIP - Non-Interest Bearing			$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$310,142	$309,719	$309,296	$308,873	$308,450	$308,027	$307,604	$307,181	$306,758	$306,335	$305,912	$305,489	$305,066	
6	Average Net Investment				309,930	309,507	309,084	308,661	308,238	307,815	307,392	306,969	306,546	306,123	305,700	305,277	
7	Return on Average Net Investment (A)																
	a. Debt Component		1.72%		445	444	444	443	443	442	441	441	440	440	439	438	5,300
	b. Equity Component Grossed Up For Taxes		6.07%		1,569	1,567	1,565	1,562	1,560	1,558	1,556	1,554	1,552	1,550	1,547	1,545	18,685
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	1.3299%			423	423	423	423	423	423	423	423	423	423	423	423	5,076
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.9290%			295	295	295	295	295	295	295	295	295	295	295	295	3,540
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$2,732	$2,729	$2,727	$2,723	$2,721	$2,718	$2,715	$2,713	$2,710	$2,708	$2,704	$2,701	$32,601
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$2,732	$2,729	$2,727	$2,723	$2,721	$2,718	$2,715	$2,713	$2,710	$2,708	$2,704	$2,701	$32,601

(A) The allowable return is per the methodology approved in Order No. PSC-2020-0165-PAA-EU.

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2021 through December 2021
CAIR Crystal River (Project 7.4 Recap)

For Project: CAIR Crystal River AFUDC - FGD Common (Project 7.4d)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	
3	Less: Accumulated Depreciation			($288,305)	(292,729)	(297,153)	(301,577)	(306,001)	(310,425)	(314,849)	(319,273)	(323,697)	(328,121)	(332,545)	(336,969)	(341,393)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$1,860,795	$1,856,371	$1,851,947	$1,847,523	$1,843,099	$1,838,675	$1,834,251	$1,829,827	$1,825,403	$1,820,979	$1,816,555	$1,812,131	$1,807,707	
6	Average Net Investment				1,858,583	1,854,159	1,849,735	1,845,311	1,840,887	1,836,463	1,832,039	1,827,615	1,823,191	1,818,767	1,814,343	1,809,919	
7	Return on Average Net Investment (A)																
	a. Debt Component		1.72%		2,669	2,663	2,656	2,650	2,644	2,637	2,631	2,625	2,618	2,612	2,606	2,599	31,610
	b. Equity Component Grossed Up For Taxes		6.07%		9,408	9,386	9,363	9,341	9,319	9,296	9,274	9,251	9,229	9,207	9,184	9,162	111,420
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	2.4700%			4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	53,088
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.0507%			91	91	91	91	91	91	91	91	91	91	91	91	1,092
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$16,592	$16,564	$16,534	$16,506	$16,478	$16,448	$16,420	$16,391	$16,362	$16,334	$16,305	$16,276	$197,210
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$16,592	$16,564	$16,534	$16,506	$16,478	$16,448	$16,420	$16,391	$16,362	$16,334	$16,305	$16,276	$197,210

For Project: Crystal River 4 and 5 - Conditions of Certification (Project 7.4q)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$83,383,699	83,383,699	83,383,699	83,383,699	83,383,699	83,383,699	83,383,699	83,383,699	83,383,699	83,383,699	83,383,699	83,383,699	83,383,699	
3	Less: Accumulated Depreciation			($2,405,761)	(2,509,018)	(2,612,275)	(2,715,532)	(2,818,789)	(2,922,046)	(3,025,303)	(3,128,560)	(3,231,817)	(3,335,074)	(3,438,331)	(3,541,588)	(3,644,845)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$80,977,938	$80,874,681	$80,771,424	$80,668,167	$80,564,910	$80,461,653	$80,358,396	$80,255,139	$80,151,882	$80,048,625	$79,945,368	$79,842,111	$79,738,854	
6	Average Net Investment				80,926,309	80,823,052	80,719,795	80,616,538	80,513,281	80,410,024	80,306,767	80,203,510	80,100,253	79,996,996	79,893,739	79,790,482	
7	Return on Average Net Investment (A)																
	a. Debt Component		1.72%		116,218	116,070	115,922	115,774	115,625	115,477	115,329	115,180	115,032	114,884	114,736	114,587	1,384,834
	b. Equity Component Grossed Up For Taxes		6.07%		409,651	409,128	408,606	408,083	407,560	407,037	406,515	405,992	405,469	404,947	404,424	403,901	4,881,313
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	1.4860%			103,257	103,257	103,257	103,257	103,257	103,257	103,257	103,257	103,257	103,257	103,257	103,257	1,239,084
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.0507%			3,521	3,521	3,521	3,521	3,521	3,521	3,521	3,521	3,521	3,521	3,521	3,521	42,252
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$632,647	$631,976	$631,306	$630,635	$629,963	$629,292	$628,622	$627,950	$627,279	$626,609	$625,938	$625,266	$7,547,483
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$632,647	$631,976	$631,306	$630,635	$629,963	$629,292	$628,622	$627,950	$627,279	$626,609	$625,938	$625,266	$7,547,483

Note> Consistent with the Stipulation & Settlement Agreement in Order No. PSC-2013-0598-FOF-EI these assets were not projected to be in-service as of year end 2013 and accordingly were not moved to base rates in 2014.
(A) The allowable return is per the methodology approved in Order No. PSC-2020-0165-PAA-EU.

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2021 through December 2021
CAIR Crystal River (Project 7.4 Recap)

For Project: CAIR Crystal River AFUDC - FGD Common (Project 7.4r) - CR4 Clinker Mitigation
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$660,998	660,998	660,998	660,998	660,998	660,998	660,998	660,998	660,998	660,998	660,998	660,998	660,998	
3	Less: Accumulated Depreciation			($120,529)	(121,890)	(123,251)	(124,612)	(125,973)	(127,334)	(128,695)	(130,056)	(131,417)	(132,778)	(134,139)	(135,500)	(136,861)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$540,469	$539,108	$537,747	$536,386	$535,025	$533,664	$532,303	$530,942	$529,581	$528,220	$526,859	$525,498	$524,137	
6	Average Net Investment				539,789	538,428	537,067	535,706	534,345	532,984	531,623	530,262	528,901	527,540	526,179	524,818	
7	Return on Average Net Investment (A)																
	a. Debt Component		1.72%		775	773	771	769	767	765	763	762	760	758	756	754	9,173
	b. Equity Component Grossed Up For Taxes		6.07%		2,732	2,726	2,719	2,712	2,705	2,698	2,691	2,684	2,677	2,670	2,664	2,657	32,335
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	2.4700%			1,361	1,361	1,361	1,361	1,361	1,361	1,361	1,361	1,361	1,361	1,361	1,361	16,332
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.0507%			28	28	28	28	28	28	28	28	28	28	28	28	336
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$4,896	$4,888	$4,879	$4,870	$4,861	$4,852	$4,843	$4,835	$4,826	$4,817	$4,809	$4,800	$58,176
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$4,896	$4,888	$4,879	$4,870	$4,861	$4,852	$4,843	$4,835	$4,826	$4,817	$4,809	$4,800	$58,176

For Project: CAIR Crystal River AFUDC - FGD Common (Project 7.4s) - CR5 Clinker Mitigation
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-21	Actual Feb-21	Actual Mar-21	Actual Apr-21	Actual May-21	Actual Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$505,904	505,904	505,904	505,904	505,904	505,904	505,904	505,904	505,904	505,904	505,904	505,904	505,904	
3	Less: Accumulated Depreciation			($79,315)	(80,356)	(81,397)	(82,438)	(83,479)	(84,520)	(85,561)	(86,602)	(87,643)	(88,684)	(89,725)	(90,766)	(91,807)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$426,589	$425,548	$424,507	$423,466	$422,425	$421,384	$420,343	$419,302	$418,261	$417,220	$416,179	$415,138	$414,097	
6	Return on Average Net Investment (A)				426,069	425,028	423,987	422,946	421,905	420,864	419,823	418,782	417,741	416,700	415,659	414,618	
7	Return on Average Net Investment																
	a. Debt Component		1.72%		612	610	609	607	606	604	603	601	600	598	597	595	7,242
	b. Equity Component Grossed Up For Taxes		6.07%		2,157	2,152	2,146	2,141	2,136	2,130	2,125	2,120	2,115	2,109	2,104	2,099	25,534
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	2.4700%			1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	12,492
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.0507%			21	21	21	21	21	21	21	21	21	21	21	21	252
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$3,831	$3,824	$3,817	$3,810	$3,804	$3,796	$3,790	$3,783	$3,777	$3,769	$3,763	$3,756	$45,520
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$3,831	$3,824	$3,817	$3,810	$3,804	$3,796	$3,790	$3,783	$3,777	$3,769	$3,763	$3,756	$45,520

Note> Consistent with the Stipulation & Settlement Agreement in Order No. PSC-2013-0598-FOF-EI these assets were not projected to be in-service as of year end 2013 and accordingly were not moved to base rates in 2014.
(A) The allowable return is per the methodology approved in Order No. PSC-2020-0165-PAA-EU.

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Commission Forms 42-1P Through 42-8P

January 2022 - December 2022
Calculation of Projected Period Amount

Docket No. 20210007-EI

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projection Amount
January 2022 - December 2022

Form 42-1P

Line		Energy ($)	Transmission Demand ($)	Distribution Demand ($)	Production Demand ($)	Total ($)
1	Total Jurisdictional Rev Req for the Projected Period					
a	Projected O&M Activities (Form 42-2P, Lines 7 through 9)	$7,851,653	$0	$0	$317,302	$8,168,955
b	Projected Capital Projects (Form 42-3P, Lines 7 through 9)	864,083	0	0	3,244,024	4,108,106
c	Total Jurisdictional Rev Req for the Projected Period (Lines 1a + 1b)	8,715,736	0	0	3,561,326	12,277,061
2	True-up for Estimated Over/(Under) Recovery for the Current Period January 2021 - December 2021 (Form 42-2E, Line 5 + 6 + 10)	1,710,639	1,924	646	(116,460)	1,596,750
3	Final True-up for the Period January 2020 - December 2020 (Form 42-1A, Line 3)	217,889	264	7	13,327	231,488
4	Total Jurisdictional Amount to Be Recovered/(Refunded) in the Projection Period January 2022 - December 2022 (Line 1 - Line 2 - Line 3)	$6,787,207	($2,188)	($654)	$3,664,458	$10,448,824

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projection Amount
January 2022 - December 2022

Form 42-2P

Docket No. 20210007-EI
Duke Energy Florida, LLC
Witness: G. P. Dean
Exh. No. __ (GPD-5)
Page 3 of 39

O&M Activities
(in Dollars)

Line		Description	Estimated Jan-22	Estimated Feb-22	Estimated Mar-22	Estimated Apr-22	Estimated May-22	Estimated Jun-22	Estimated Jul-22	Estimated Aug-22	Estimated Sep-22	Estimated Oct-22	Estimated Nov-22	Estimated Dec-22	End of Period Total
1		O&M Activities - System													
	1	Transmission Substation Environmental Investigation, Remediation and Pollution Prevention	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	1a	Distribution Substation Environmental Investigation, Remediation and Pollution Prevention	0	0	0	0	0	0	0	0	0	0	0	0	0
	2	Distribution System Environmental Investigation, Remediation and Pollution Prevention	0	0	0	0	0	0	0	0	0	0	0	0	0
	3	Pipeline Integrity Management - Bartow/Anclote Pipeline - Intm	0	0	0	0	0	0	0	0	0	0	0	0	0
	4	Above Ground Tank Secondary Containment - Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0
	5	SO2/NOx Emissions Allowances - Energy	986	967	1,553	1,182	1,289	1,289	1,433	1,350	1,262	1,312	662	848	14,134
	6	Phase II Cooling Water Intake 316(b) - Base	0	0	0	20,000	0	0	0	0	0	0	0	0	20,000
	6a	Phase II Cooling Water Intake 316(b) - Intm	0	20,833	20,833	20,834	20,833	20,833	20,834	0	10,000	85,000	20,000	20,000	260,000
	7.2	CAIR/CAMR - Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0
	7.4	CAIR/CAMR Crystal River - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
	7.4	CAIR/CAMR Crystal River - Energy	531,503	541,537	763,587	600,363	740,384	689,863	725,279	753,530	724,758	689,409	357,556	442,456	7,560,224
	7.4	CAIR/CAMR Crystal River - A&G	0	0	0	0	0	0	0	0	0	0	0	0	0
	7.4	CAIR/CAMR Crystal River - Conditions of Certification - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	7.5	Best Available Retrofit Technology (BART) - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	8	Arsenic Groundwater Standard - Base	5,367	5,367	5,367	5,367	5,367	5,367	5,367	5,367	5,367	10,367	10,367	5,367	74,401
	9	Sea Turtle - Coastal Street Lighting - Distrib	0	0	0	0	0	0	0	0	0	0	0	0	0
	11	Modular Cooling Towers - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
	12	Greenhouse Gas Inventory and Reporting - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	13	Mercury Total Daily Maximum Loads Monitoring - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	14	Hazardous Air Pollutants (HAPs) ICR Program - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	15	Effluent Limitation Guidelines ICR Program - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	15.1	Effluent Limitation Guidelines Program CRN - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	16	National Pollutant Discharge Elimination System (NPDES) - Energy	0	0	0	4,700	6,100	0	0	0	9,800	4,700	6,100	0	31,400
	17	Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy	20,000	63,500	89,500	0	9,091	0	0	0	0	9,091	0	0	191,182
	17.1	Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	17.2	Mercury & Air Toxic Standards (MATS) CR1 & CR2 - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	18	Coal Combustion Residual (CCR) Rule - Energy	16,486	40,986	24,486	18,986	54,986	21,486	16,486	18,986	16,486	16,486	37,486	59,486	342,830
2		Total O&M Activities - Recoverable Costs	$574,342	$673,190	$905,326	$671,432	$838,049	$738,837	$769,398	$779,232	$767,673	$816,365	$432,171	$528,157	$8,494,170
3		Recoverable Costs Allocated to Energy	568,975	646,990	879,126	625,232	811,849	712,637	743,197	773,865	752,306	720,998	401,804	502,790	8,139,770
4		Recoverable Costs Allocated to Demand - Transm	0	0	0	0	0	0	0	0	0	0	0	0	0
		Recoverable Costs Allocated to Demand - Distrib	0	0	0	0	0	0	0	0	0	0	0	0	0
		Recoverable Costs Allocated to Demand - Prod-Base	5,367	5,367	5,367	25,367	5,367	5,367	5,367	5,367	5,367	10,367	10,367	5,367	94,401
		Recoverable Costs Allocated to Demand - Prod-Intm	0	20,833	20,833	20,834	20,833	20,833	20,834	0	10,000	85,000	20,000	20,000	260,000
		Recoverable Costs Allocated to Demand - Prod-Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0
		Recoverable Costs Allocated to Demand - A&G	0	0	0	0	0	0	0	0	0	0	0	0	0
5		Retail Energy Jurisdictional Factor	0.97955	0.97713	0.95072	0.97138	0.97055	0.96353	0.95034	0.95576	0.96452	0.96282	0.97472	0.96865	
6		Retail Transmission Demand Jurisdictional Factor	0.71994	0.71994	0.71994	0.71994	0.71994	0.71994	0.71994	0.71994	0.71994	0.71994	0.71994	0.71994	
		Retail Distribution Demand Jurisdictional Factor	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	
		Retail Production Demand Jurisdictional Factor - Base	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	
		Retail Production Demand Jurisdictional Factor - Intm	0.88321	0.88321	0.88321	0.88321	0.88321	0.88321	0.88321	0.88321	0.88321	0.88321	0.88321	0.88321	
		Retail Production Demand Jurisdictional Factor - Peaking	0.90678	0.90678	0.90678	0.90678	0.90678	0.90678	0.90678	0.90678	0.90678	0.90678	0.90678	0.90678	
		Retail Production Demand Jurisdictional Factor - A&G	0.95415	0.95415	0.95415	0.95415	0.95415	0.95415	0.95415	0.95415	0.95415	0.95415	0.95415	0.95415	
7		Jurisdictional Energy Recoverable Costs (A)	557,338	632,195	835,805	607,336	787,940	686,648	706,293	739,627	725,612	694,189	391,644	487,026	7,851,653
8		Jurisdictional Demand Recoverable Costs - Transm (B)	0	0	0	0	0	0	0	0	0	0	0	0	0
		Jurisdictional Demand Recoverable Costs - Distrib (B)	0	0	0	0	0	0	0	0	0	0	0	0	0
		Jurisdictional Demand Recoverable Costs - Prod-Base (B)	4,984	4,984	4,984	23,557	4,984	4,984	4,984	4,984	4,984	9,627	9,627	4,984	87,667
		Jurisdictional Demand Recoverable Costs - Prod-Intm (B)	0	18,400	18,400	18,401	18,400	18,400	18,401	0	8,832	75,073	17,664	17,664	229,635
		Jurisdictional Demand Recoverable Costs - Prod-Peaking (B)	0	0	0	0	0	0	0	0	0	0	0	0	0
		Jurisdictional Demand Recoverable Costs - A&G (B)	0	0	0	0	0	0	0	0	0	0	0	0	0
9		Total Jurisdictional Recoverable Costs - O&M Activities (Lines 7 + 8)	$562,322	$655,579	$859,189	$649,294	$811,324	$710,032	$729,678	$744,611	$739,428	$778,889	$418,935	$509,674	$8,168,955

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projection Amount
January 2022 - December 2022

Form 42-3P

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line		Description	Estimated Jan-22	Estimated Feb-22	Estimated Mar-22	Estimated Apr-22	Estimated May-22	Estimated Jun-22	Estimated Jul-22	Estimated Aug-22	Estimated Sep-22	Estimated Oct-22	Estimated Nov-22	Estimated Dec-22	End of Period Total
1		Investment Projects - System (A)													
	3.1	Pipeline Integrity Management - Bartow/Anclote Pipeline - Intm	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	4.1	Above Ground Tank Secondary Containment - Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0
	4.2	Above Ground Tank Secondary Containment - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
	4.3	Above Ground Tank Secondary Containment - Intm	0	0	0	0	0	0	0	0	0	0	0	0	0
	5	SO2/NOX Emissions Allowances - Energy	20,281	20,276	20,268	20,259	20,251	20,243	20,235	20,226	20,217	20,209	20,203	20,199	242,867
	6	Phase II Cooling Water Intake 316(b) - Base	119,356	119,102	118,847	118,593	118,339	118,085	117,831	117,577	117,322	117,069	116,815	116,560	1,415,496
	6.1	Phase II Cooling Water Intake 316(b) - Base - Bartow	281	842	1,404	1,965	2,527	3,089	3,651	4,212	4,774	5,335	5,897	6,458	40,435
	6.2	Phase II Cooling Water Intake 316(b) - Intermediate - Anclote	0	0	0	0	0	0	0	0	0	0	0	0	0
	7.1	CAIR/CAMR Anclote- Intm	0	0	0	0	0	0	0	0	0	0	0	0	0
	7.2	CAIR/CAMR - Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0
	7.3	CAMR Crystal River - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
	7.4	CAIR/CAMR Crystal River AFUDC - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
	7.4	CAIR/CAMR Crystal River AFUDC - Energy	19,315	19,315	19,315	19,315	19,315	19,315	19,315	19,315	19,315	19,315	19,315	19,315	231,778
	7.5	Best Available Retrofit Technology (BART) - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	9	Sea Turtle - Coastal Street Lighting -Distrib	0	0	0	0	0	0	0	0	0	0	0	0	0
	10.1	Underground Storage Tanks - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
	10.2	Underground Storage Tanks - Intm	0	0	0	0	0	0	0	0	0	0	0	0	0
	11	Modular Cooling Towers - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
	11.1	Crystal River Thermal Discharge Compliance Project - Base (Post 2012)	0	0	0	0	0	0	0	0	0	0	0	0	0
	11.1	Crystal River Thermal Discharge Compliance Project - Base (2012)	0	0	0	0	0	0	0	0	0	0	0	0	0
	15.1	Effluent Limitation Guidelines CRN (ELG) - Base	26,770	26,700	26,632	26,564	26,496	26,427	26,359	26,291	26,222	26,153	26,085	26,016	316,715
	16	National Pollutant Discharge Elimination System (NPDES) - Intm	105,452	105,232	105,013	104,794	104,575	104,356	104,137	103,917	103,698	103,479	103,260	103,042	1,250,955
	17	Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy	35,534	35,437	35,341	35,244	35,147	35,050	34,953	34,857	34,760	34,663	34,567	34,470	420,023
	17.1	Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion -	0	0	0	0	0	0	0	0	0	0	0	0	0
	17.2	Mercury & Air Toxic Standards (MATS) CR1 & CR2 - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	18	Coal Combustion Residual (CCR) Rule - Base	44,862	44,749	44,636	44,523	44,409	44,296	44,184	44,070	43,957	43,844	43,731	43,617	530,878
2		Total Investment Projects - Recoverable Costs	$371,851	$371,653	$371,456	$371,257	$371,059	$370,861	$370,665	$370,465	$370,265	$370,067	$369,873	$369,677	$4,449,147
3		Recoverable Costs Allocated to Energy	75,130	75,028	74,924	74,818	74,713	74,608	74,503	74,398	74,292	74,187	74,085	73,984	894,668
		Recoverable Costs Allocated to Distribution Demand	0	0	0	0	0	0	0	0	0	0	0	0	0
4		Recoverable Costs Allocated to Demand - Production - Base	191,269	191,393	191,519	191,645	191,771	191,897	192,025	192,150	192,275	192,401	192,528	192,651	2,303,524
		Recoverable Costs Allocated to Demand - Production - Intermediate	105,452	105,232	105,013	104,794	104,575	104,356	104,137	103,917	103,698	103,479	103,260	103,042	1,250,955
		Recoverable Costs Allocated to Demand - Production - Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0
5		Retail Energy Jurisdictional Factor	0.97955	0.97713	0.95072	0.97138	0.97055	0.96353	0.95034	0.95576	0.96452	0.96282	0.97472	0.96865	
		Retail Distribution Demand Jurisdictional Factor	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	
6		Retail Demand Jurisdictional Factor - Production - Base	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	
		Retail Demand Jurisdictional Factor - Production - Intermediate	0.88321	0.88321	0.88321	0.88321	0.88321	0.88321	0.88321	0.88321	0.88321	0.88321	0.88321	0.88321	
		Retail Demand Jurisdictional Factor - Production - Peaking	0.90678	0.90678	0.90678	0.90678	0.90678	0.90678	0.90678	0.90678	0.90678	0.90678	0.90678	0.90678	
7		Jurisdictional Energy Recoverable Costs (B)	73,593	73,312	71,232	72,676	72,513	71,887	70,803	71,106	71,656	71,428	72,212	71,664	864,083
		Jurisdictional Demand Recoverable Costs - Distribution (B)	0	0	0	0	0	0	0	0	0	0	0	0	0
8		Jurisdictional Demand Recoverable Costs - Production - Base (C)	177,622	177,737	177,854	177,971	178,088	178,205	178,324	178,440	178,556	178,673	178,791	178,905	2,139,168
		Jurisdictional Demand Recoverable Costs - Production - Intermediate (C)	93,136	92,942	92,749	92,555	92,362	92,168	91,975	91,781	91,587	91,394	91,200	91,008	1,104,856
		Jurisdictional Demand Recoverable Costs - Production - Peaking (C)	0	0	0	0	0	0	0	0	0	0	0	0	0
9		Total Jurisdictional Recoverable Costs - Investment Projects (Lines 7 + 8)	$344,352	$343,991	$341,834	$343,203	$342,962	$342,260	$341,102	$341,327	$341,799	$341,495	$342,203	$341,577	$4,108,106

Notes:

(A) Each project's Total System Recoverable Expenses on Form 42-4P, Line 9; Form 42-4P, Line 5 for Projects 5 - Emission Allowances and Project 7. 4 - Reagents.
(B) Line 3 x Line 5
(C) Line 4 x Line 6

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projection Amount
January 2022 - December 2022

Docket No. 20210007-EI
Duke Energy Florida, LLC
Witness: G. P. Dean
Exh. No. __ (GPD-5)

SO2 and NOx EMISSIONS ALLOWANCES - Energy (Project 5)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-22	Estimated Feb-22	Estimated Mar-22	Estimated Apr-22	Estimated May-22	Estimated Jun-22	Estimated Jul-22	Estimated Aug-22	Estimated Sep-22	Estimated Oct-22	Estimated Nov-22	Estimated Dec-22	End of Period Total
1	Working Capital Dr (Cr)															
	a. 0158150 SO_2 Emission Allowance Inventory		$3,209,227	$3,208,240	$3,207,273	$3,205,720	$3,204,538	$3,203,249	$3,201,960	$3,200,527	$3,199,177	$3,197,915	$3,196,604	$3,195,941	$3,195,093	$3,195,093
	b. 0254020 Auctioned SO_2 Allowance		$0	0	0	0	0	0	0	0	0	0	0	0	0	0
	c. 0158170 NOx Emission Allowance Inventory		0	0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Total Working Capital		$3,209,227	$3,208,240	$3,207,273	$3,205,720	$3,204,538	$3,203,249	$3,201,960	$3,200,527	$3,199,177	$3,197,915	$3,196,604	$3,195,941	$3,195,093	$3,195,093
3	Average Net Investment			$3,208,734	$3,207,757	$3,206,497	$3,205,129	$3,203,893	$3,202,605	$3,201,244	$3,199,852	$3,198,546	$3,197,259	$3,196,272	$3,195,517	
4	Return on Average Net Working Capital Balance (B)															
	a. Debt Component	1.70%		4,532	4,531	4,529	4,527	4,525	4,524	4,522	4,520	4,518	4,516	4,515	4,514	54,273
	b. Equity Component Grossed Up For Taxes	5.89%		15,749	15,745	15,739	15,732	15,726	15,719	15,713	15,706	15,699	15,693	15,688	15,685	188,594
5	Total Return Component (C)			$20,281	$20,276	$20,268	$20,259	$20,251	$20,243	$20,235	$20,226	$20,217	$20,209	$20,203	$20,199	242,867
6	Expense Dr (Cr)															
	a. 0509030 SO_2 Allowance Expense			$986	$967	$1,553	$1,182	$1,289	$1,289	$1,433	$1,350	$1,262	$1,312	$662	$848	14,134
	b. 0407426 Amortization Expense			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. 0 509212 NOx Allowance Expense			0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
7	Net Expense (D)			986	967	1,553	1,182	1,289	1,289	1,433	1,350	1,262	1,312	662	848	14,134
8	Total System Recoverable Expenses (Lines 5 + 7)			$21,267	$21,243	$21,821	$21,441	$21,540	$21,532	$21,668	$21,576	$21,479	$21,521	$20,865	$21,047	257,001
	a. Recoverable costs allocated to Energy			$21,267	$21,243	$21,821	$21,441	$21,540	$21,532	$21,668	$21,576	$21,479	$21,521	$20,865	$21,047	257,001
	b. Recoverable costs allocated to Demand			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
9	Energy Jurisdictional Factor			0.97955	0.97713	0.95072	0.97138	0.97055	0.96353	0.95034	0.95576	0.96452	0.96282	0.97472	0.96865	
10	Demand Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Retail Energy-Related Recoverable Costs (E)			$20,832	$20,757	$20,746	$20,828	$20,905	$20,746	$20,592	$20,621	$20,717	$20,721	$20,338	$20,387	248,191
12	Retail Demand-Related Recoverable Costs (F)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
13	Total Jurisdictional Recoverable Costs (Lines 11 + 12)			$ 20,832	$ 20,757	$ 20,746	$ 20,828	$ 20,905	$ 20,746	$ 20,592	$ 20,621	$ 20,717	$ 20,721	$ 20,338	$ 20,387	$ 248,191

Notes:

(A) N/A
(B) Line 3 x 7.58% x 1/12. Based on ROE of 9.85%, weighted cost of equity component of capital structure of 4.33% and statutory tax rate of 25.345% (inc tax multiplier = 1.3394950).
(C) Line 5 is reported on Capital Schedule
(D) Line 7 is reported on O&M Schedule
(E) Line 8a x Line 9
(F) Line 8b x Line 10

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projection Amount
January 2022 - December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Phase II Cooling Water Intake 316(b) - Base (Project 6)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-22	Estimated Feb-22	Estimated Mar-22	Estimated Apr-22	Estimated May-22	Estimated Jun-22	Estimated Jul-22	Estimated Aug-22	Estimated Sep-22	Estimated Oct-22	Estimated Nov-22	Estimated Dec-22	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$12,505,047	12,505,047	12,505,047	12,505,047	12,505,047	12,505,047	12,505,047	12,505,047	12,505,047	12,505,047	12,505,047	12,505,047	12,505,047	
3	Less: Accumulated Depreciation		(46,273)	(86,478)	(126,683)	(166,888)	(207,093)	(247,298)	(287,503)	(327,708)	(367,913)	(408,118)	(448,323)	(488,528)	(528,733)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$12,458,774	$12,418,569	$12,378,364	$12,338,159	$12,297,954	$12,257,749	$12,217,544	$12,177,339	$12,137,134	$12,096,929	$12,056,724	$12,016,519	$11,976,314	
6	Average Net Investment			$12,438,671	$12,398,466	$12,358,261	$12,318,056	$12,277,851	$12,237,646	$12,197,441	$12,157,236	$12,117,031	$12,076,826	$12,036,621	$11,996,416	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.70%		17,570	17,513	17,456	17,399	17,342	17,286	17,229	17,172	17,115	17,059	17,002	16,945	207,088
	b. Equity Component Grossed Up For Taxes	5.89%		61,053	60,856	60,658	60,461	60,264	60,066	59,869	59,672	59,474	59,277	59,080	58,882	719,612
	c. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	3.8582%		40,205	40,205	40,205	40,205	40,205	40,205	40,205	40,205	40,205	40,205	40,205	40,205	482,460
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.000507		528	528	528	528	528	528	528	528	528	528	528	528	6,336
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$119,356	$119,102	$118,847	$118,593	$118,339	$118,085	$117,831	$117,577	$117,322	$117,069	$116,815	$116,560	1,415,496
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			119,356	119,102	118,847	118,593	118,339	118,085	117,831	117,577	117,322	117,069	116,815	116,560	1,415,496
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor			0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)			110,840	110,604	110,367	110,131	109,896	109,660	109,424	109,188	108,951	108,716	108,480	108,243	1,314,500
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$110,840	$110,604	$110,367	$110,131	$109,896	$109,660	$109,424	$109,188	$108,951	$108,716	$108,480	$108,243	$1,314,500

Notes:

(A) N/A
(B) Line 6 x 7.58% x 1/12. Based on ROE of 9.85%, weighted cost of equity component of capital structure of 4.33% and statutory tax rate of 25.345% (inc tax multiplier = 1.3394950).
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order No. PSC-2021-0202-AS-EI.
(D) Line 2 x rate x 1/12. Based on 2020 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projection Amount
January 2022 - December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Phase II Cooling Water Intake 316(b) - Base - Bartow (Project 6.1)
(in Dollars)

Line	Description	Beginning of Period Amount	Estimated Jan-22	Estimated Feb-22	Estimated Mar-22	Estimated Apr-22	Estimated May-22	Estimated Jun-22	Estimated Jul-22	Estimated Aug-22	Estimated Sep-22	Estimated Oct-22	Estimated Nov-22	Estimated Dec-22	End of Period Total
1	Investments														
	a. Expenditures/Additions		$88,848	$88,848	$88,848	$88,848	$88,848	$88,848	$88,848	$88,848	$88,848	$88,848	$88,848	$88,848	$1,066,178
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing	0	88,848	177,696	266,545	355,393	444,241	533,089	621,937	710,785	799,634	888,482	977,330	1,066,178	
5	Net Investment (Lines 2 + 3 + 4)	$0	$88,848	$177,696	$266,545	$355,393	$444,241	$533,089	$621,937	$710,785	$799,634	$888,482	$977,330	$1,066,178	
6	Average Net Investment		$44,424	$133,272	$222,120	$310,969	$399,817	$488,665	$577,513	$666,361	$755,209	$844,058	$932,906	$1,021,754	
7	Return on Average Net Investment (B)														
	a. Debt Component 1.70%		63	188	314	439	565	690	816	941	1,067	1,192	1,318	1,443	9,036
	b. Equity Component Grossed Up For Taxes 5.89%		218	654	1,090	1,526	1,962	2,399	2,835	3,271	3,707	4,143	4,579	5,015	31,399
	c. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation (C) 3.8582%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D) 0.000507		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		$281	$842	$1,404	$1,965	$2,527	$3,089	$3,651	$4,212	$4,774	$5,335	$5,897	$6,458	40,435
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		281	842	1,404	1,965	2,527	3,089	3,651	4,212	4,774	5,335	5,897	6,458	40,435
10	Energy Jurisdictional Factor		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)		0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	
12	Retail Energy-Related Recoverable Costs (E)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)		261	782	1,304	1,825	2,347	2,869	3,391	3,911	4,433	4,954	5,476	5,997	37,550
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$261	$782	$1,304	$1,825	$2,347	$2,869	$3,391	$3,911	$4,433	$4,954	$5,476	$5,997	$37,550

Notes:

(A) N/A
(B) Line 6 x 7.58% x 1/12. Based on ROE of 9.85%, weighted cost of equity component of capital structure of 4.33% and statutory tax rate of 25.345% (inc tax multiplier = 1.3394950).
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order No. PSC-2021-0202-AS-EI.
(D) Line 2 x rate x 1/12. Based on 2020 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projection Amount
January 2022 - December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Phase II Cooling Water Intake 316(b) - Intermediate - Anclote (Project 6.2)
(in Dollars)

Line	Description	Beginning of Period Amount	Estimated Jan-22	Estimated Feb-22	Estimated Mar-22	Estimated Apr-22	Estimated May-22	Estimated Jun-22	Estimated Jul-22	Estimated Aug-22	Estimated Sep-22	Estimated Oct-22	Estimated Nov-22	Estimated Dec-22	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
6	Average Net Investment		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
7	Return on Average Net Investment (B)														
	a. Debt Component 1.70%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Equity Component Grossed Up For Taxes 5.89%		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation (C) 10.3694%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D) 0.005960		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)		0.88321	0.88321	0.88321	0.88321	0.88321	0.88321	0.88321	0.88321	0.88321	0.88321	0.88321	0.88321	
12	Retail Energy-Related Recoverable Costs (E)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Line 6 x 7.58% x 1/12. Based on ROE of 9.85%, weighted cost of equity component of capital structure of 4.33% and statutory tax rate of 25.345% (inc tax multiplier = 1.3394950).
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order No. PSC-2021-0202-AS-EI.
(D) Line 2 x rate x 1/12. Based on 2020 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projection Amount
January 2022 - December 2022

Docket No. 20210007-EI
Duke Energy Florida, LLC
Witness: G. P. Dean
Exh. No. __ (GPD-5)

Schedule of Amortization and Return
For Project: CAIR/CAMR - Energy (Project 7.4 - Reagents and By-Products)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-22	Estimated Feb-22	Estimated Mar-22	Estimated Apr-22	Estimated May-22	Estimated Jun-22	Estimated Jul-22	Estimated Aug-22	Estimated Sep-22	Estimated Oct-22	Estimated Nov-22	Estimated Dec-22	End of Period Total
1	Working Capital Dr (Cr)															
	a. 0154401 Ammonia Inventory		$1,343,285	$1,343,285	$1,343,285	$1,343,285	$1,343,285	$1,343,285	$1,343,285	$1,343,285	$1,343,285	$1,343,285	$1,343,285	$1,343,285	$1,343,285	1,343,285
	b. 0154200 Limestone Inventory		$1,712,468	1,712,468	1,712,468	1,712,468	1,712,468	1,712,468	1,712,468	1,712,468	1,712,468	1,712,468	1,712,468	1,712,468	1,712,468	1,712,468
2	Total Working Capital		$3,055,753	3,055,753	3,055,753	3,055,753	3,055,753	3,055,753	3,055,753	3,055,753	3,055,753	3,055,753	3,055,753	3,055,753	3,055,753	3,055,753
3	Average Net Investment			3,055,753	3,055,753	3,055,753	3,055,753	3,055,753	3,055,753	3,055,753	3,055,753	3,055,753	3,055,753	3,055,753	3,055,753	
4	Return on Average Net Working Capital Balance (A)															
	a. Debt Component	1.70%		4,316	4,316	4,316	4,316	4,316	4,316	4,316	4,316	4,316	4,316	4,316	4,316	$51,795
	b. Equity Component Grossed Up For Taxes	5.89%		14,999	14,999	14,999	14,999	14,999	14,999	14,999	14,999	14,999	14,999	14,999	14,999	179,983
5	Total Return Component (B)			19,315	19,315	19,315	19,315	19,315	19,315	19,315	19,315	19,315	19,315	19,315	19,315	231,778
6																
	a. 0502010 Ammonia Expense			271,900	277,100	389,800	306,700	379,100	352,900	370,700	385,800	371,300	351,900	182,600	225,900	3,865,700
	b. 0502040 Limestone Expense			413,657	405,531	650,922	495,542	539,958	539,805	600,169	565,083	528,289	550,643	277,661	355,773	5,923,033
	c. 0502050 Dibasic Acid Expense			2,600	2,800	3,800	3,000	3,700	3,400	3,600	3,800	3,700	3,400	1,800	2,200	37,800
	d. 0502070 Gypsum Disposal/Sale			(404,655)	(396,794)	(637,035)	(485,079)	(528,674)	(528,642)	(587,890)	(553,653)	(517,731)	(538,134)	(271,606)	(347,917)	(5,797,810)
	e. 0502040 Hydrated Lime Expense			248,000	252,900	356,100	280,200	346,300	322,400	338,700	352,500	339,200	321,600	167,100	206,500	3,531,500
	f. 0502300 Caustic Expense			0	0	0	0	0	0	0	0	0	0	0	0	0
7	Net Expense (C)			531,503	541,537	763,587	600,363	740,384	689,863	725,279	753,530	724,758	689,409	357,556	442,456	7,560,224
8	Total System Recoverable Expenses (Lines 5 + 7)			$550,817	$560,852	$782,902	$619,678	$759,699	$709,177	$744,593	$772,844	$744,073	$708,724	$376,870	$461,771	$7,792,002
	a. Recoverable Costs Allocated to Energy			550,817	560,852	782,902	619,678	759,699	709,177	744,593	772,844	744,073	708,724	376,870	461,771	7,792,002
	b. Recoverable Costs Allocated to Demand			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9	Energy Jurisdictional Factor			0.97955	0.97713	0.95072	0.97138	0.97055	0.96353	0.95034	0.95576	0.96452	0.96282	0.97472	0.96865	
10	Demand Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Retail Energy-Related Recoverable Costs (D)			539,552	548,027	744,323	601,942	737,325	683,315	707,620	738,651	717,671	682,371	367,341	447,293	7,515,431
12	Retail Demand-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Total Jurisdictional Recoverable Costs (Lines 11 + 12)			$ 539,552	$ 548,027	$ 744,323	$ 601,942	$ 737,325	$ 683,315	$ 707,620	$ 738,651	$ 717,671	$ 682,371	$ 367,341	$ 447,293	$ 7,515,431

Notes:

(A) Line 3 x 7.58% x 1/12. Based on ROE of 9.85%, weighted cost of equity component of capital structure of 4.33% and statutory tax rate of 25.345% (inc tax multiplier = 1.3394950).
(B) Line 5 is reported on Capital Schedule
(C) Line 7 is reported on O&M Schedule
(D) Line 8a x Line 9
(E) Line 8b x Line 10

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projection Amount
January 2022 - December 2022

Docket No. 20210007-EI
Duke Energy Florida, LLC
Witness: G. P. Dean
Exh. No. __ (GPD-5)
Page 10 of 39

Return on Capital Investments, Depreciation and Taxes
For Project: Effluent Limitation Guidelines CRN - Base (Project 15.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-22	Estimated Feb-22	Estimated Mar-22	Estimated Apr-22	Estimated May-22	Estimated Jun-22	Estimated Jul-22	Estimated Aug-22	Estimated Sep-22	Estimated Oct-22	Estimated Nov-22	Estimated Dec-22	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$2,612,979	2,612,979	2,612,979	2,612,979	2,612,979	2,612,979	2,612,979	2,612,979	2,612,979	2,612,979	2,612,979	2,612,979	2,612,979	
3	Less: Accumulated Depreciation		(102,323)	(113,147)	(123,971)	(134,795)	(145,619)	(156,443)	(167,267)	(178,091)	(188,915)	(199,739)	(210,563)	(221,387)	(232,211)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$2,510,656	$2,499,832	$2,489,008	$2,478,184	$2,467,360	$2,456,536	$2,445,712	$2,434,888	$2,424,064	$2,413,240	$2,402,416	$2,391,592	$2,380,768	
6	Average Net Investment			$2,505,244	$2,494,420	$2,483,596	$2,472,772	$2,461,948	$2,451,124	$2,440,300	$2,429,476	$2,418,652	$2,407,828	$2,397,004	$2,386,180	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.70%		3,539	3,523	3,508	3,493	3,478	3,462	3,447	3,432	3,416	3,401	3,386	3,370	41,455
	b. Equity Component Grossed Up For Taxes	5.89%		12,297	12,243	12,190	12,137	12,084	12,031	11,978	11,925	11,872	11,818	11,765	11,712	144,052
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C) 4.9707%			10,824	10,824	10,824	10,824	10,824	10,824	10,824	10,824	10,824	10,824	10,824	10,824	129,888
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D) 0.000507			110	110	110	110	110	110	110	110	110	110	110	110	1,320
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$26,770	$26,700	$26,632	$26,564	$26,496	$26,427	$26,359	$26,291	$26,222	$26,153	$26,085	$26,016	316,715
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			26,770	26,700	26,632	26,564	26,496	26,427	26,359	26,291	26,222	26,153	26,085	26,016	316,715
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)			24,860	24,795	24,732	24,669	24,606	24,541	24,478	24,415	24,351	24,287	24,224	24,160	294,117
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$24,860	$24,795	$24,732	$24,669	$24,606	$24,541	$24,478	$24,415	$24,351	$24,287	$24,224	$24,160	$294,117

Notes:

(A) N/A
(B) Line 6 x 7.58% x 1/12. Based on ROE of 9.85%, weighted cost of equity component of capital structure of 4.33% and statutory tax rate of 25.345% (inc tax multiplier = 1.3394950).
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order No. PSC-2021-0202-AS-EI.
(D) Line 2 x rate x 1/12. Based on 2020 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projection Amount
January 2022 - December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: NPDES - Intermediate (Project 16)
(in Dollars)

Line	Description	Beginning of Period Amount	Estimated Jan-22	Estimated Feb-22	Estimated Mar-22	Estimated Apr-22	Estimated May-22	Estimated Jun-22	Estimated Jul-22	Estimated Aug-22	Estimated Sep-22	Estimated Oct-22	Estimated Nov-22	Estimated Dec-22	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	$12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	
3	Less: Accumulated Depreciation	(3,000,702)	(3,035,369)	(3,070,036)	(3,104,703)	(3,139,370)	(3,174,037)	(3,208,704)	(3,243,371)	(3,278,038)	(3,312,705)	(3,347,372)	(3,382,039)	(3,416,706)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$9,841,168	$9,806,501	$9,771,834	$9,737,167	$9,702,500	$9,667,833	$9,633,166	$9,598,499	$9,563,832	$9,529,165	$9,494,498	$9,459,831	$9,425,164	
6	Average Net Investment		$9,823,835	$9,789,168	$9,754,501	$9,719,834	$9,685,167	$9,650,500	$9,615,833	$9,581,166	$9,546,499	$9,511,832	$9,477,165	$9,442,498	
7	Return on Average Net Investment (B)														
	a. Debt Component 1.70%		13,876	13,827	13,778	13,729	13,680	13,631	13,582	13,533	13,484	13,435	13,386	13,338	163,279
	b. Equity Component Grossed Up For Taxes 5.89%		48,219	48,048	47,878	47,708	47,538	47,368	47,198	47,027	46,857	46,687	46,517	46,347	567,392
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation (C) 3.239%		34,667	34,667	34,667	34,667	34,667	34,667	34,667	34,667	34,667	34,667	34,667	34,667	416,004
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D) 0.008120		8,690	8,690	8,690	8,690	8,690	8,690	8,690	8,690	8,690	8,690	8,690	8,690	104,280
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		$105,452	$105,232	$105,013	$104,794	$104,575	$104,356	$104,137	$103,917	$103,698	$103,479	$103,260	$103,042	1,250,955
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		$105,452	$105,232	$105,013	$104,794	$104,575	$104,356	$104,137	$103,917	$103,698	$103,479	$103,260	$103,042	1,250,955
10	Energy Jurisdictional Factor		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)		0.88321	0.88321	0.88321	0.88321	0.88321	0.88321	0.88321	0.88321	0.88321	0.88321	0.88321	0.88321	
12	Retail Energy-Related Recoverable Costs (E)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)		93,136	92,942	92,749	92,555	92,362	92,168	91,975	91,781	91,587	91,394	91,200	91,008	1,104,856
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$93,136	$92,942	$92,749	$92,555	$92,362	$92,168	$91,975	$91,781	$91,587	$91,394	$91,200	$91,008	$1,104,856

Notes:

(A) N/A
(B) Line 6 x 7.58% x 1/12. Based on ROE of 9.85%, weighted cost of equity component of capital structure of 4.33% and statutory tax rate of 25.345% (inc tax multiplier = 1.3394950).
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order No. PSC-2021-0202-AS-EI.
(D) Line 2 x rate x 1/12. Based on 2020 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projection Amount
January 2022 - December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: MERCURY & AIR TOXIC STANDARDS (MATS) - CRYSTAL RIVER UNITS 4 & 5 - Energy (Project 17)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-22	Estimated Feb-22	Estimated Mar-22	Estimated Apr-22	Estimated May-22	Estimated Jun-22	Estimated Jul-22	Estimated Aug-22	Estimated Sep-22	Estimated Oct-22	Estimated Nov-22	Estimated Dec-22	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	
3	Less: Accumulated Depreciation		(503,933)	(519,219)	(534,505)	(549,791)	(565,077)	(580,363)	(595,649)	(610,935)	(626,221)	(641,507)	(656,793)	(672,079)	(687,365)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$3,186,254	$3,170,968	$3,155,682	$3,140,396	$3,125,110	$3,109,824	$3,094,538	$3,079,252	$3,063,966	$3,048,680	$3,033,394	$3,018,108	$3,002,822	
6	Average Net Investment			$3,178,611	$3,163,325	$3,148,039	$3,132,753	$3,117,467	$3,102,181	$3,086,895	$3,071,609	$3,056,323	$3,041,037	$3,025,751	$3,010,465	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.70%		4,490	4,468	4,447	4,425	4,403	4,382	4,360	4,339	4,317	4,295	4,274	4,252	52,452
	b. Equity Component Grossed Up For Taxes	5.89%		15,602	15,527	15,452	15,377	15,302	15,226	15,151	15,076	15,001	14,926	14,851	14,776	182,267
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C) 4.9707%			15,286	15,286	15,286	15,286	15,286	15,286	15,286	15,286	15,286	15,286	15,286	15,286	183,432
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D) 0.000507			156	156	156	156	156	156	156	156	156	156	156	156	1,872
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$35,534	$35,437	$35,341	$35,244	$35,147	$35,050	$34,953	$34,857	$34,760	$34,663	$34,567	$34,470	420,023
	a. Recoverable Costs Allocated to Energy			35,534	35,437	35,341	35,244	35,147	35,050	34,953	34,857	34,760	34,663	34,567	34,470	420,023
	b. Recoverable Costs Allocated to Demand			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
10	Energy Jurisdictional Factor			0.97955	0.97713	0.95072	0.97138	0.97055	0.96353	0.95034	0.95576	0.96452	0.96282	0.97472	0.96865	
11	Demand Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
12	Retail Energy-Related Recoverable Costs (E)			$34,807	$34,627	$33,600	$34,235	$34,112	$33,772	$33,217	$33,315	$33,527	$33,374	$33,693	$33,389	$405,668
13	Retail Demand-Related Recoverable Costs (F)			0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$34,807	$34,627	$33,600	$34,235	$34,112	$33,772	$33,217	$33,315	$33,527	$33,374	$33,693	$33,389	$405,668

Notes:

(A) N/A
(B) Line 6 x 7.58% x 1/12. Based on ROE of 9.85%, weighted cost of equity component of capital structure of 4.33% and statutory tax rate of 25.345% (inc tax multiplier = 1.3394950).
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order No. PSC-2021-0202-AS-EI.
(D) Line 2 x rate x 1/12. Based on 2020 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projection Amount
January 2022 - December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: COAL COMBUSTION RESIDUAL (CCR) RULE - Base (Project 18)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-22	Estimated Feb-22	Estimated Mar-22	Estimated Apr-22	Estimated May-22	Estimated Jun-22	Estimated Jul-22	Estimated Aug-22	Estimated Sep-22	Estimated Oct-22	Estimated Nov-22	Estimated Dec-22	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$4,320,358	4,320,358	4,320,358	4,320,358	4,320,358	4,320,358	4,320,358	4,320,358	4,320,358	4,320,358	4,320,358	4,320,358	4,320,358	
3	Less: Accumulated Depreciation (A)		($73,985)	(91,881)	(109,777)	(127,673)	(145,569)	(163,465)	(181,361)	(199,257)	(217,153)	(235,049)	(252,945)	(270,841)	(288,737)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$4,246,373	$4,228,477	$4,210,581	$4,192,685	$4,174,789	$4,156,893	$4,138,997	$4,121,101	$4,103,205	$4,085,309	$4,067,413	$4,049,517	$4,031,621	
6	Average Net Investment			$4,237,425	$4,219,529	$4,201,633	$4,183,737	$4,165,841	$4,147,945	$4,130,049	$4,112,153	$4,094,257	$4,076,361	$4,058,465	$4,040,569	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.70%		5,985	5,960	5,935	5,910	5,884	5,859	5,834	5,808	5,783	5,758	5,733	5,707	70,156
	b. Equity Component Grossed Up For Taxes	5.89%		20,799	20,711	20,623	20,535	20,447	20,359	20,272	20,184	20,096	20,008	19,920	19,832	243,786
	c. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	4.9707%		17,896	17,896	17,896	17,896	17,896	17,896	17,896	17,896	17,896	17,896	17,896	17,896	214,752
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.000507		182	182	182	182	182	182	182	182	182	182	182	182	2,184
	e. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$44,862	$44,749	$44,636	$44,523	$44,409	$44,296	$44,184	$44,070	$43,957	$43,844	$43,731	$43,617	530,878
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			44,862	44,749	44,636	44,523	44,409	44,296	44,184	44,070	43,957	43,844	43,731	43,617	530,878
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor			0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	0.92865	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)			41,661	41,556	41,451	41,346	41,240	41,135	41,031	40,926	40,821	40,716	40,611	40,505	493,000
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$41,661	$41,556	$41,451	$41,346	$41,240	$41,135	$41,031	$40,926	$40,821	$40,716	$40,611	$40,505	$493,000

Notes:

(A) N/A
(B) Line 6 x 7.58% x 1/12. Based on ROE of 9.85%, weighted cost of equity component of capital structure of 4.33% and statutory tax rate of 25.345% (inc tax multiplier = 1.3394950).
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order No. PSC-2021-0202-AS-EI.
(D) Line 2 x rate x 1/12. Based on 2020 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Project Title: **Substation Environmental Investigation, Remediation and Pollution Prevention**
Project No. 1

Project Description:
Chapter 376 Florida Statutes requires that any person discharging a prohibited pollutant shall undertake to contain, remove and abate the discharge to the satisfaction of the FDEP. Similarly, Chapter 403 Florida Statutes provides that it is prohibited to cause pollution so as to harm or injure human health or welfare, animal, plant, or aquatic life or property. For DEF to comply with these statutes, it is actively conducting remediation and pollution prevention activities at its substation sites to remove the existence of pollutant discharges. Activities also include development and implementation of best management and pollution prevention measures at these sites.

Project Accomplishments:
The remediation portion of the Substation Assessment and Remedial Action Plan has been completed for all of the 279 SARAP substation sites. The Amended Deed Restrictive Covenant ("DRC") for West Lake Wales Substation has been approved by FDEP. The proposed DRC for Central Florida Substation submitted for approval to FDEP in July 2020. Project is complete as of first quarter 2021.

Project Fiscal Expenditures:
2021 O&M expenditures for the substation system program (Projects 1 & 1a) are estimated to be $263. This program is now complete.

Project Progress Summary:
This project is complete as of 1st quarter 2021.

Project Projections:
No further charges are expected to hit this project in 2022.

Project Title: **Distribution System Environmental Investigation, Remediation and Pollution Prevention**
Project No. 2

Project Description:
Chapter 376 Florida Statutes requires that any person discharging a prohibited pollutant shall undertake to contain, remove and abate the discharge to the satisfaction of the FDEP. Similarly, Chapter 403 Florida Statutes provides that it is prohibited to cause pollution so as to harm or injure human health or welfare, animal, plant, or aquatic life or property. For DEF to comply with these statutes, it is actively conducting remediation and pollution prevention activities at its distribution sites to remove the existence of pollutant discharges. Activities also include development and implementation of best management and pollution prevention measures at these sites.

Project Accomplishments:
All TRIP sites source removals are completed. The Final TRIP has been completed and the NAM report submitted to FDEP 4-4-19.

Project Fiscal Expenditures:
No further charges are expected to hit this project in 2021.

Project Progress Summary:
This project is complete.

Project Projections:
No further charges are expected to hit this project in 2022.

Project Title: **Pipeline Integrity Management (PIM) - Bartow/Anclote Pipeline**
Project No. 3

Project Description:
The U.S. Department of Transportation (USDOT) Regulation 49 CFR Part 195, as amended effective 2/15/02, and the new regulation published at 67 Federal Register 2136 on 1/16/02, requires DEF to implement a PIM program. Prior to the 2/15/02 amendments, the USDOT's PIM regulations applied only to operators with 500 miles or more of hazardous liquid and carbon dioxide pipelines that could affect high consequence areas. The amendments which became effective on 2/15/02, extended the requirements for implementing integrity management to operators who have less than 500 miles of regulated pipelines. As such, DEF must maintain the integrity of pipeline systems in order to protect public safety and the environment, and comply with continual assessment and evaluation of pipeline systems integrity through inspection or testing, data integration and analysis, and follow up with remedial, preventative, and mitigative actions. DEF owns one hazardous liquid pipeline, Bartow/Anclote 14-inch hot oil pipeline, extending 33.3 miles from the Company's Bartow Plant north of St. Petersburg to the Anclote Plant in Holiday, that is subject to PIM regulations.

Effective 2/2010, amendments to 49 CFR 195 were finalized to improve opportunities to reduce risk through more effective control of pipelines. Compliance with these amendments will enhance pipeline safety by coupling strengthened control room management with improved controller training and fatigue management. On 6/16/11, the USDOT published in the Federal Register (V0l. 76, 35130-35136), a final rule effective 8/15/11, that expedites the program implementation deadlines in the Control Room Management/Human Factors regulations in order to realize the safety benefits sooner than established in the original rule. This final rule amends the program implementation deadlines for different procedures to no later than 10/21/11 and 8/1/12.

Project Accomplishments:
Since the Bartow Anclote Pipeline (BAP) contained a small quantity of #6 fuel oil, the PIM program under 49CFR195 continues to be maintained. Third party projects by Florida Department of Transportation (FDOT), Florida Gas Transmission, Pinellas County, The City of Pinellas Park, and others have been evaluated for their risk to BAP integrity. Risk mitigation measures have been completed per 49CFR195.450. The BAP Risk Analysis has been updated. The Annual Report and National Pipeline Mapping System (NPMS) annual review have been completed. Reviews and evaluations are also being completed for Advisory Bulletins 11-04, 13-02, 15-01, and 15-02, relating to flooding and hurricanes. BAP personnel have participated in US Department of Transportation Pipeline and Hazardous Material Safety Administration (PHMSA), utility owners groups, damage prevention groups, and FDOT workshops and training. Pipeline accidents and PHMSA enforcement actions have been reviewed for conditions that are applicable to the BAP and appropriate changes to BAP practices and procedures have been implemented. Pipeline records are being organized and stored with the conversion to electronic storage now essentially complete.

In 2016, pipeline ownership was transferred from the Fossil Hydro Operations group to Plant Retirement and Demolition, in preparation for pipeline retirement that is expected to occur in 2016. Once retired, the pipeline will be cleaned to remove any remaining oil. Once cleaned, the requirements described above in the PIM program will no longer be required. Cleaning is expected to occur in 2016, with any required demolition activities in 2017. As of the end of 2016, three of the four sub-projects were retired and approved to be amortized over three years - Project 3.1b Pipeline Leak Detection, Project 3.1c Pipeline Controls Upgrade, and Project 3.1d Control Room Management.

The final sub-project 3.1a - Alderman Road Fence was retired June 2017 and approved as a regulatory asset. This was amortized over 26 months, and all four parts of this project are fully amortized as of September 2019.

Project Fiscal Expenditures:
No capital or O&M expenditures are estimated for 2021.

Project Progress Summary:
Projects 3.1b (Pipeline leak Detection), 3.1c (Pipeline Controls Upgrade), and 3.1d (Control Room Management) were retired August 2016. Project 3.1a (Alderman Road Fence) retired June 2017. All are fully amortized as of September 2019.

Project Projections:
No capital or O&M expenditures are estimated for 2022.

Project Title: **Above Ground Storage Tank Secondary Containment**
Project No. 4

Project Description:
FDEP Rule 62-761.510(3) states that DEF is required to make improvements to its above ground petroleum storage tanks in order to comply with those provisions. Subsection (d) of the rule requires all internally lined single bottom above ground storage tanks to be upgraded with secondary containment, including secondary containment for piping in contact with the soil. Rule 62-761.500(1)(e) also requires that dike field area containment for pre-1998 tanks be upgraded, if needed, to comply with the requirement.

Project Accomplishments:
DEF has completed work at Debary 1 and 2, Turner 7, Turner 8, Higgins 1, and Bartow 6 as well as Turner P-1 and P-2 piping work.

Project Fiscal Expenditures:
No project expenditures are expected in 2021.

Project Progress Summary:
DEF continually evaluates its compliance program, including project prioritization, schedule and technology applications. Project 4.1a (Turner CTs) retired in March 2016.

Project was moved to base rates as of January 2022, per Order No. PSC-2021-0202-AS-EI.

Project Projections:
No new project expenditures are expected in 2022.

Project Title: **SO_2 and NOx Emissions Allowances**
Project No. 5

Project Description:
In accordance with the Acid Rain Program in Title IV of the Clean Air Act, CFR 40 Part 73 and Part 76, Florida Administrative Code Rule 62-214 and the Clean Air Interstate Rule (CAIR), DEF manages sulfur dioxide (SO_2) and nitrogen oxide (NOx) allowance inventory to offset emissions. On 7/6/11, the EPA issued the Cross-State Air Pollution Rule (CSAPR) to replace the CAIR. The CSAPR significantly alters SO_2 and NOx allowance programs. Under the CAIR, Florida has to comply with annual SO_2 and NOx emission requirements, and seasonal NOx emission requirements. Under the CSAPR, Florida is no longer required to comply with annual emissions requirements, only ozone seasonal limits. On 8/8/11, the final CSAPR was published in the Federal Register. The CSAPR sets state-level annual and seasonal SO_2 and NOx emission allowance requirements effective 1/1/12.

On 8/21/12, the D.C. Circuit Court vacated the CSAPR. It also directed the EPA to continue administering the CAIR which requires additional reductions in SO_2 and NOx emissions beginning in 2015. On 4/29/14, the U.S. Supreme Court reversed the D.C. Circuit Court decision finding that with CSAPR the EPA reasonably interpreted the good neighbor provision of the Clean Air Act. The case was then remanded to the D.C. Circuit Court for further proceedings, and the EPA requested the court lift the CSAPR stay and direct it to take effect on 1/1/15. On 10/23/14 the D.C. Circuit Court lifted the CSAPR stay. On 1/1/15, the CSAPR replaced the CAIR. The CSAPR took effect in Florida on 5/1/15. Consequently, CAIR NOx emission allowances have no value; however, SO2 emission allowances can continue to be used to comply with the Acid Rain Program. DEF treated its unused NOx costs as a regulatory asset amortizing it over 3 years, as approved by the Commission in Order No. PSC-2011-0553-FOF-EI. These are fully recovered as of December 2017.

Project Accomplishments:
Air quality compliance costs are administered by an authorized account representative who evaluates a variety of resources and options. Activities performed include purchases of SO2 and NOx emissions allowances as well as auctions and transfers of SO2 emissions allowances.

Project Fiscal Expenditures:
2021 O&M is forecasted to be $12k.

Project Progress Summary:
DEF continually evaluates the status of emission rules to maximize the cost effectiveness of its compliance strategy.

Project Projections:
2022 O&M expenditures are projected to be $14k.

Project Title: **Phase II Cooling Water Intake**
Project No. 6

Project Description:
Section 316(b) of the Federal Clean Water Act requires that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. 33 U.S.C. Section 1326. On 5/19/14, the EPA Administrator signed a final 316(b) rule to protect fish and aquatic life drawn into cooling systems at power plant and factories. The rule aims to minimize impingement (aquatic life pinned against cooling water intake structures) and entrainment (aquatic life drawn into cooling water systems). The regulation became effective on October 14, 2014, 60 days after publication in the Federal Register which was 8/15/14.

EPA's regulation implementing §316(b) of the Clean Water Act for existing facilities was published on August 15, 2014. The regulation aims to minimize adverse environmental impacts to fish and other aquatic organisms from the operation of cooling water intake structures. The regulation became effective October 14, 2014, 60 days after publication in the Federal Register. The regulation primarily applies to existing power generating facilities that commenced construction prior to or on January 17, 2002 and to new units at existing facilities that are built to increase the generating capacity of the facility.

According to the current 316(b) rule, required studies and information submittals will be due with the renewal of the NPDES permit application for permits that expire after July 18, 2018. Permittees with a current NPDES permit that expires before July 18, 2018 may request the FDEP establish an alternative schedule for submitting the required information. This rule is applicable to Anclote, Bartow, Suwannee, and Crystal River North stations.

Project Accomplishments:
DEF is currently evaluating the 316(b) rule to determine potential study requirements, operating and cost impacts to its generating stations. Site specific strategic plans, studies, and implementation plans are under development to ensure compliance with all applicable requirements of the rule.

Project Fiscal Expenditures:
2021 O&M expenditures are estimated to be $30k. 2021 Capital expenditures are estimated to be $2.2M.

Project Progress Summary:
Required 316(b) reports have been finalized and with the NPDES permit renewal applications to FDEP for review and approval. Anclote & Bartow permit applications have been filed with FDEP.

Project Projections:
2022 estimated O&M expenditures are $280k, and capital $1.1M.

Project Title: **Integrated Clean Air Compliance Plan - Clean Air Interstate Rule (CAIR)**
Project Nos. (7.2, 7.3 & 7.4)

Project Description:
The Clean Air Interstate Rule (CAIR), 40 CFR 24, 262, imposes significant restrictions on emissions of SO_2 and NOx from power plants in 28 eastern states, including Florida and the District of Columbia. The CAIR rule apportions region-wide SO_2 and NOx emission reduction requirements to the individual states, and further requires each affected state to revise its State Implementation Plans (SIPs) to include measures necessary to achieve its emission reduction budget within prescribed deadlines.

The Cross-State air pollution Rule (CSAPR) replaced CAIR on 1/1/15. Under the CSAPR, the State of Florida is no longer required to comply with annual emission requirements, only NOx ozone seasonal limits. The CSAPR requirements took effect in Florida on 5/1/15, the beginning of the ozone season. NOx emission allowances under CAIR have no value; however, DEF will continue to use its SO2 emission allowances to comply with the Acid Rain Program. (see Project No. 5 - SO2 and NOx Emission Allowances Project Sheet for more information).

The Florida Department of Environmental Protection ("FDEP") Conditions of Certification, dated August 1, 2012, require DEF to evaluate an alternative disposal method of FGD Blowdown wastewater based on results of groundwater monitoring near percolation ponds. DEF is installing a physical/chemical treatment system to treat FGD Blowdown wastewater with discharge to surface water or percolation ponds.

Project Accomplishments:
The FGD Wastewater treatment (WWT) system went in-service February 2019.

All projects except 7.4 CAIR/CAMR Crystal River - Energy (Reagents) have been moved to base rates as of January 2022, as approved in Order No. PSC-2021-0202-AS-EI.

Project Fiscal Expenditures:
For 2021, O&M expenditures for CAIR/CAMR – Peaking (Project 7.2) are projected to be $0. For the CAIR/CAMR Crystal River Program (Project 7.4), O&M is forecasted be $19.9M.

Project Progress Summary:
DEF continues to comply with the CAIR, CSAPR and the Acid Rain Program.

Project Projections:
2022 estimated O&M expenditures are $7.6M.

Project Title: **Best Available Retrofit Technology (BART)**
Project No. 7.5

Project Description:
On 5/25/12, the EPA proposed a partial disapproval of Florida's proposed Regional Haze State Implementation Plan (SIP) because the proposed SIP relies on CAIR to satisfy BART requirements for SO_2 and NOx emissions. CAIR remained in effect while litigation against the Cross State Air Pollution Rule (CSAPR) proceeded, and the EPA incorporated the CSAPR in place of CAIR into Regional Haze SIPs, including Florida. DEF worked with the FDEP to develop specific BART and Reasonable Progress permits for affected units that were incorporated into Florida's revised SIP submittal, which was filed with EPA on 9/17/12. The final BART permit applications for Crystal River fossil units were submitted to EPA on 10/15/12 as a supplement to the 9/17/12 submittal. Permitting was finalized in 2013 with an effective date of January 1, 2014.

Project Accomplishments:
DEF performed required emissions modeling and associated BART analysis for Crystal River 1&2 (CR1&2) and Anclote plants, developed and submitted a Reasonable Progress evaluation for Crystal River 4&5, developed and submitted necessary BART Implementation Plans and air construction permit applications in support of the FDEP's work to amend its SIP as directed by the EPA. Permitting actions were completed in 2013 with the effective date of the CR 1& 2 permit being January 1, 2014.

Project Fiscal Expenditures:
No project expenditures are expected in 2021.

Project Progress Summary:
DEF performed required emissions modeling and associated BART analysis for CR1&2 and Anclote, developed and submitted a Reasonable Progress evaluation for Crystal River 4&5, developed and submitted necessary BART Implementation Plans and air construction permit applications needed in support of the FDEP ongoing work to amend its State Implementation Plan as directed by the EPA. Based on the revised Regional Haze SIP incorporating the provisions of Crystal River's BART permits for SO_2 and NOx, EPA on 12/10/12 proposed approval of the SIP. In August 2013, EPA finalized the full approval of the SIP. The Crystal River South BART permit became effective on January 1, 2014 and DEF is now operating under the terms of that permit.

Project Projections:
No project expenditures are expected in 2022.

Project Title: **Arsenic Groundwater Standard**
Project No. 8

Project Description:
On 12/22/01, the EPA adopted a new maximum contaminant level (MCL) for arsenic in drinking water replacing the previous standard of 0.050 mg/L (50 ppb) with a new MCL of 0.010 mg/L (10 ppb). Effective 1/1/05, the FDEP established the USEPA MCL as Florida's drinking water standard. See Rule 62-550 F.A.C. The new standard has compliance implications for land application and water reuse projects in Florida with arsenic ground water monitoring levels above 10 ppb because the drinking water standard has been established as the groundwater standard by Rule 62-520-420(1), F.A.C.

Project Accomplishments:
A Plan of Study (POS) to evaluate the source of arsenic at the site was implemented on November 2011. A POS Addendum that included a leachability study and proposed abandoning one well and installing 3 new wells was implemented in February 2012. An additional Flue Gas Desulfurization (FGD) Wastewater Treatment Study was conducted in May 2013. The results of these studies indicated that Arsenic is naturally occurring in some areas but there is also a contribution from the FGD discharge from the lined treatment pond to the percolation ponds, and from the industrial wastewater from Crystal River Units 1 & 2. These sources are being addressed by the construction of a new FGD wastewater treatment system and retirement of Units 1 & 2, both scheduled to be completed by December 31, 2018.
Additional assessment was initiated in 2016 around the area of ground water wells still exceeding the Arsenic standard of 10 ppb with no clear source of Arsenic identified (MWC-1, MWC-31 and MWC-32). This additional assessment indicated that the source of Arsenic around MWC-31 is related to the former North Ash Pond that was located in that area. Based on that finding, the Consent Order was amended to address that area under 62-780, F.A.C. Remedial Actions, which included additional assessment and submittal of a final assessment report to FDEP in 2018.
Results from MWC-1 assessment indicate that the well is not measuring impacts from the industrial wastewater activities at the site and DEF requested to FDEP that the well be replaced by one of the Plan of Study wells. FDEP requested the sampling of all the wells around MWC-1 for a year prior to approval of the change.

Project Fiscal Expenditures:
2021 O&M expenditures are expected to be $269k.

Project Progress Summary:
Continuation of groundwater monitoring, analysis and reporting of results to FDEP.

Project Projections:
2022 O&M expenditures are forecasted to be $74k.

Project Title: **Sea Turtle - Coastal Street Lighting**
Project No. 9

Project Description:
DEF owns and leases high pressure sodium streetlights throughout its service territory, including areas along the Florida coast. Pursuant to Section 161.163, Florida Statutes, the FDEP, in collaboration with the Florida Fish and Wildlife Conservation Commission (FFWCC) and the U.S. Fish & Wildlife Service (USFWS), has developed a model Sea Turtle lighting ordinance. The model ordinance is used by the local governments to develop and implement ordinances within its jurisdiction. To date, Sea Turtle lighting ordinances have been adopted in Franklin County, Gulf County, City of Mexico Beach in Bay County and Pinellas County, all of which are within DEF's service territory. Since 2004, officials from the various local governments, as well as the FDEP, FFWC, and USFWS, have advised DEF that lighting it owns and leases is affecting turtle nesting areas that fall within the scope of these ordinances. As a result, local governments require DEF to take additional measures to satisfy new criteria being applied to ensure compliance with the sea turtle ordinances.

Project Accomplishments:
DEF continues to work with Franklin County, Gulf County, City of Mexico Beach in Bay County, and Pinellas County to mitigate any potential sea turtle nesting issues by retrofitting existing street lights, placing amber shields on existing HPS street lights and monitoring street lights for effectiveness in complying with sea turtle ordinances.

Project Fiscal Expenditures:
2021 Capital expenditures are estimated to be $0, O&M expenditures are estimated to be a $0.

Project Progress Summary:
DEF is on schedule with activities identified for this program.

This project was moved to base rates as of January 2022, as approved in Order No. PSC-2021-0202-AS-EI.

Project Projections:
There are no Capital or O&M costs estimated for 2022.

Project Title: **Underground Storage Tanks**
Project No. 10

Project Description:
FDEP regulations require that underground pollutant storage tanks and small diameter piping be upgraded with secondary containment by 12/31/09. See Rule 62-761.510(5), F.A.C. DEF identified four tanks that must comply with this rule: two at Crystal River Plant and two at Bartow Plant.

Project Accomplishments:
Work on Crystal River and Bartow USTs was completed in 4th Qtr 2006.

Project Fiscal Expenditures:
There are no 2021 estimated expenditures for this project.

Project Progress Summary:
DEF continually evaluates its compliance program, including project prioritization, schedule and technology applications.

This project was moved to base rates as of January 2022, as approved in Order No. PSC-2021-0202-AS-EI.

Project Projections:
No 2022 expenditures are expected for this project.

Project Title: **Modular Cooling Towers**
Project No. 11

Project Description:
This project involves installation and operation of modular cooling towers in the summer months to minimize de-rates of Crystal River 1&2 (CR1&2) necessary to comply with the NPDES permit limit for the temperature of cooling water discharged from the units.

Project Accomplishments:
Vendors of modular cooling towers were evaluated regarding cost of installation and operation. The FDEP reviewed the project and approved operation. A vendor was selected and the towers were installed during the 2nd Qtr 2006.

Project Fiscal Expenditures:
There are no 2021 estimated expenditures for this project.

Project Progress Summary:
The modular cooling towers began operation in June 2006 and successfully minimized de-rates of CR 1&2. The towers were removed during the first half of 2012. This project is complete.

Project Projections:
No 2022 expenditures are expected for this project.

Project Title: **Crystal River Thermal Discharge Compliance Project**
Project No. 11.1

Project Description:
This project was to evaluate and implement the best long term solution to maintain compliance with the thermal discharge limit in the FDEP industrial wastewater permit for Crystal River Units 1,2&3 that was being addressed in the short term by the Modular Cooling Towers approved in Docket No. 20060162-EI. Due to DEF's decision to retire CR3, this project is no longer necessary and will not be implemented.

Project Accomplishments:
The study phase of the project was completed with a recommendation to replace the leased modular cooling towers in coordination with the cooling solution for the CR3 Extended Power Uprate (EPU) discharge canal cooling solution. The new cooling tower associated with the CR3 EPU was to be sized to mitigate both increased temperatures from the EPU as well as replace the modular cooling towers, which were removed in 2012. The design contract for the CR3 EPU cooling tower was awarded and a vendor selected. In February 2013, DEF decided to retire CR3; therefore, the project will not proceed.

Project Fiscal Expenditures:
There are no 2021 estimated expenditures for this project.

Project Progress Summary:
Crystal River Units 1,2&3 utilize a once-through cooling water process to cool and condense turbine exhaust steam back to water. The cooling water is removed from the Gulf of Mexico via an intake canal and discharged to a common discharge canal shared by all of the generating units. DEF has a NPDES industrial wastewater permit from the FDEP to discharge this cooling water from CR 1,2&3 into the Gulf of Mexico. The FDEP NPDES permit includes a limit on the temperature of the cooling water discharge (96.5 degrees Fahrenheit on a three-hour rolling average) measured at the point of discharge to the Gulf of Mexico. The new cooling towers were being added as a long term solution to the issue of higher ambient water temperatures previously being addressed by the modular cooling towers and added heat rejection due to the estimated 180MW Uprate of CR3. With the retirement of CR3, the heat rejection associated with the entire unit is removed and therefore the new cooling tower is not necessary for the continued operation of CR 1&2 within the NPDES permit limits.

Project Projections:
No 2022 expenditures are expected for this project.

Project Title: **Greenhouse Gas (GHG) Inventory and Reporting**
Project No. 12

Project Description:
The GHG Inventory and Reporting Program was created in response to Chapter 2008-277, Florida Laws, which established the Florida Climate Protection Act to be codified at section 403.44, Florida Statutes. Among other things, this legislation authorizes the FDEP to establish a cap and trade program for GHG emissions from power plants. Utilities subject to the program, including DEF, will be required to use The Climate Registry for purposes of GHG emission registration and reporting. The requirement to report to The Climate Registry was repealed during the 2010 legislative session; however, the EPA GHG Reporting Rule (40 CFR 98) does require DEF to submit 2010 GHG data to the EPA no later than 9/30/2011.

Project Accomplishments:
In 2009, DEF joined The Climate Registry and submitted 2008 GHG inventory data. 2009 data was submitted during the third quarter of 2010. Both 2008 and 2009 data was validated by a third party as required by The Climate Registry. 2010 GHG inventory data was submitted to EPA on 9/30/11 and EPA does not require data validation by a third party. DEF has discontinued its membership with The Climate Registry. Since third party validation is not required by the EPA, no future expenditures will be incurred by DEF, resulting in the completion of this project.

Project Fiscal Expenditures:
There are no 2021 estimated expenditures for this project.

Project Progress Summary:
DEF submits GHG inventory data directly to EPA which does not require third party validation. Membership with The Climate Registry has been discontinued.

Project Projections:
No 2022 expenditures are expected for this project.

Project Title: **Mercury Total Daily Maximum Loads Monitoring (TMDL)**
Project No. 13

Project Description:
Section 303(d) of the Federal Clean Water Act requires each state to identify state waters not meeting water quality standards and establish a TMDL for the pollutant or pollutants causing the failure to meet standards. Under a 1999 federal consent decree, TMDLs for over 100 Florida water bodies listed as impaired for mercury must be established by 9/12/12. The FDEP has initiated a research program to provide necessary information for setting appropriate TMDLs for mercury. Among other things, the study will assess the relative contributions of mercury-emitting sources, such as coal-fired power plants, to mercury levels in surface waters.

Project Accomplishments:
Atmospheric & Environmental Research, Inc (AER) completed the literature review on mercury deposition in Florida. This document was sent to the FDEP Division of Air Resource Management and the TMDL team for review in February 2009. In addition, the Florida Electric Power Coordinating Group (FCG) Mercury Task Force met with FDEP Division of Air Resource Management to discuss the review in January 2010. AER performed Florida mercury deposition modeling for the Division of Air Resource Management. The FCG Mercury Task Force contracted with Tetra Tech to conduct aquatic field sampling, including an aquatics modeling report, to develop a "Conceptual Model for the Florida Mercury TMDL." This document was finalized and submitted to the FDEP in December 2010. Key personnel from AER were employed by Environ in 2011 and FCG established a contract with Environ to ensure continuity of the project. FCG used Environ and Tetra Tech to review and critique FDEP's aquatic cycling and atmospheric modeling analyses. The FDEP developed a mercury TMDL report in the spring and summer of 2012, and it proposed a TMDL in September 2012. The EPA approved Florida's statewide mercury TMDL in a letter dated October 18, 2013. Florida's mercury TMDL covers 441 waters listed as impaired for mercury based on fish tissue mercury levels. EPA's approval letter states that if FDEP identifies any new waters to be listed as impaired for mercury, a new TMDL will not be required if the listing is caused by the factors addressed in the approved TMDL. Conversely, a new TMDL, addressing the newly listed water body, would be required if "local emission or effluent sources" are determined to be the cause of the elevated fish tissue levels that required the new listing.

Project Fiscal Expenditures:
There are no 2021 estimated expenditures for this project.

Project Progress Summary:
The mercury TMDL study concluded in 2012.

Project Projections:
No 2022 expenditures are expected for this project.

Project Title: **Hazardous Air Pollutants (HAPs) ICR Program**
Project No. 14

Project Description:
In 2009, the EPA initiated efforts to develop an Information Collection Request (ICR), which requires that owners/operators of all coal- and oil-fired electric utility steam generating units provide information that will allow the EPA to assess emissions of hazardous air pollutants from each such unit. The intention of the ICR is to assist the Administrator of the EPA in developing national emission standards for hazardous air pollutants under Section 112(d) of the Clean Air Act, 42 U.S.C. 7412. Pursuant to those efforts, by letter dated 12/24/09, the EPA formally requested DEF comply with certain data collection and emissions testing requirements for several of its steam electric generating units. The EPA letter states that initial submittal of existing information must be made within 90 days, and that the remaining data must be submitted within 8 months. Collection and submittal of the requested information is mandatory under Section 114 of the Clean Air Act, 42 U.S.C. 7414.

Project Accomplishments:
DEF completed and submitted the ICR to EPA during 2010. The HAPS ICR project is complete.

Project Fiscal Expenditures:
There are no 2021 estimated expenditures for this project.

Project Progress Summary:
DEF completed and submitted the ICR to EPA during 2010.

Project Projections:
No 2022 expenditures are expected for this project.

Project Title: **Effluent Limitation Guidelines ICR Program**
Project No. 15

Project Description:
The Effluent Limitation Guidelines ICR Program was created in response to Section 304 of the Federal Clean Water Act which directs the EPA to develop and periodically review regulations, called effluent guidelines, to limit the amount of pollutants that are discharged to surface waters from various point source categories. 33 U.S.C. §13 14(b). In October 2009, the EPA announced that it intended to update the effluent guidelines for the steam electric power generating point source category, which were last updated in 1982. DEF is required to complete the ICR and submit responses to the EPA within 90 days. Collection and submittal of the requested information is mandatory under Section 308 of the Clean Water Act.

Project Accomplishments:
DEF completed and submitted the ICR to the EPA in September 2010. The Effluent Limitation Guidelines ICR Program is complete.

Project Fiscal Expenditures:
There are no 2021 estimated expenditures for this project.

Project Progress Summary:
DEF completed and submitted the ICR to EPA in September 2010.

Project Projections:
No 2022 expenditures are expected for this project.

Project Title: **Effluent Limitation Guidelines CRN Program**
Project No. 15.1

Project Description:
On September 30th, 2015, U.S. Environmental Protection Agency finalized the Steam Electric Power Generating Effluent Guidelines, 40 CFR Part 423, imposing federal standards on several power plant streams that are discharged to surface water. In the final regulation, closed-loop systems or dry handling have been identified as the Best Available Technology ("BAT") for bottom ash transport water. Crystal River North Units 4 & 5 have a dry bottom ash system that utilizes dewatering bins for separation of bottom ash and water. However, the current configuration has the potential for bottom ash transport water to leave via overflows and drain into an NPDES internal outfall. Achieving the closed loop bottom ash compliance requirement is as soon as possible beginning November 1, 2018 but no later than December 31, 2023. Renewal of the Crystal River Units 4 & 5 NPDES permit is in progress and addresses this requirement. Duke Energy is seeking a compliance date of February 1, 2020 to include modification of the existing system.

Project Accomplishments:
DEF Initiated the first phase of ELG compliance activities necessary to comply with NPDES permit renewal. The remaining project scope is still on hold pending EPA Administrative Stay final decision.

Project Fiscal Expenditures:
There are no 2021 estimated expenditures for this project.

Project Progress Summary:
This project was placed in-service June 2020.

Project Projections:
No capital or O&M expenditures are forecasted for 2022.

Project Title: **National Pollutant Discharge Elimination System (NPDES)**
Project No. 16

Project Description:
Pursuant to the Federal Clean Water Act, 33 U.S.C. § 1342, all point source discharges to navigable waters from industrial facilities must obtain permits under the NPDES Program. The FDEP administers the NPDES program in Florida. DEF's Anclote, Bartow, and Crystal River North, Crystal River South, and Suwannee NPDES permits were issued on 11/25/2015, 1/5/2016, 7/18/11, 4/7/2014, and 10/6/2016, respectively. Crystal River North NPDES permit is in the renewal process. All facilities are required to meet new permitting conditions. In Docket No. 20110007-EI, the Commission approved recovery of costs associated with new requirements included or expected to be included in the new renewal permits, including: thermal studies, aquatic organism return studies and implementation, whole effluent toxicity (WET) testing, dissolved oxygen (DO) studies (Bartow only), and freeboard limitation related studies (Bartow only). As noted in DEF's 2/8/12 program update, on 12/14/11, the FDEP issued a final NPDES renewal permit and associated Administrative Order (AO) for the Suwannee Plant. The AO includes a new requirement to assess copper discharges that DEF did not anticipate when it filed its petition in 2011.

Project Accomplishments:
DEF continues to perform whole effluent toxicity testing, implementing initial 316(b) rule requirements based on NPDES permit schedules at affected facilities which includes literature review and analysis, additional field study, and reporting requirements in accordance to NPDES permit requirements. Bartow freeboard limitation study was completed in May 2011 and submitted to FDEP on 6/23/11. The FDEP approved DEF's corrective action plan and Bartow is in compliance with Administrative Order as of December 2014. The copper discharge study at the Suwannee plant has been completed and a final report was submitted to the FDEP in June 2014 resulting in a corrective action of retiring the steam units. The Suwannee plant retired Units 1, 2 and 3 in December 2016.

Project Fiscal Expenditures:
2021 O&M expenditures are estimated to be $52k. No capital expenditures are forecasted for 2021.

Project Progress Summary:
DEF has begun complying with the requirements of the NPDES permits. Aquatic organism return study requirements have been postponed to align with the final EPA 316(b) rule requirements (Bartow/Anclote Plants) which was published 8/15/14. The aquatic organism return requirement is not a requirement in the Crystal River North NPDES permit. The dissolved oxygen study of cooling water intake and discharge at the Bartow plant was completed and the results of the study demonstrated there is no negative impact on DO due to the plant's operation. The final DO report was submitted to the FDEP on November 20, 2012, and the Department has not required any additional action. The Suwannee Steam station was retired and removed from service; therefore, WET testing is no longer required.

Project Projections:
2022 estimated O&M expenditures are $32k. No capital expenditures are expected in 2022.

Project Title: **Mercury & Air Toxic Standards (MATS) CR4 & CR5**
Project No. 17

Project Description:
The Commission approved ECRC recovery of DEF's costs for compliance with new hazardous air pollutant standards at Crystal River Units 4 & 5 (CR4&5) in Order No. PSC-2011-0553-FOF-EI. The final MATS rule was issued by the EPA on 12/21/11. The FDEP granted a limited, one-year extension for the mercury-related requirements on 3/12/15. DEF will utilize the co-benefits of existing FGD and SCR systems as the primary MATS emission controls. CR4&5 have demonstrated compliance with all MATS requirements as of 4/16/16.

Project Accomplishments:
DEF installed oxidation-reduction potential (ORP) probes and mercury re-emission control systems for MATS emissions control. In addition, continuous emissions monitoring systems (CEMS) were installed for compliance demonstration with particulate matter (PM) and mercury emissions. Appendix K sorbent traps have been certified and maintained to serve as backup monitors for mercury CEMS.

Project Fiscal Expenditures:
2021 O&M expenditures are estimated to be $245K.

Project Progress Summary:
Initial implementation of the CR4&5 MATS compliance plan is complete.

Project Projections:
2022 estimated O&M is $191k. No capital expenditures are forecasted.

Project Title: **Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion**
Project No. 17.1

Project Description:
Convert existing Anclote Units to use 100% natural gas to be in compliance with MATS as approved by the Commission in Order No. PSC-2012-0432-PAA-EI.

Project Accomplishments:
Unit 1 and Unit 2 gas conversions were completed 7/13/13 and 12/2/13, respectively. Unit 1 and Unit 2 Forced Draft (FD) fan modification work was completed 5/22/14 and 11/17/14, respectively.

Project Fiscal Expenditures:
No 2021 expenditures are expected for this project.

Project Progress Summary:
This project is in-service.

This project was moved to base rates as of January 2022 per Order No. PSC-2021-0202-AS-EI.

Project Projections:
No 2022 expenditures are expected for this project.

Project Title: **Mercury & Air Toxic Standards (MATS) CR1 & CR2**
Project No. 17.2

Project Description:
DEF implemented its CR1&2 MATS Compliance Plan as approved by the Commission in Order No. PSC-2014-0173-PAA-EI. CR1&2 have demonstrated compliance with all MATS requirements as of 4/16/2016.

Project Accomplishments:
DEF finalized its CR1&2 MATS Compliance Plan in December 2013 and began implementation in early 2014. Modifications were made to the electrostatic precipitators (ESPs) to improve particulate collection efficiency, and reagent injection systems were installed to reduce hydrogen chloride (HCl) and mercury emissions. Appendix K sorbent traps were installed for compliance demonstration with mercury emissions.

Project Fiscal Expenditures:
No further Capital or O&M expenses are forecasted.

Project Progress Summary:
CR1&2 have been retired as of December 2020.

Project Projections:
No further Capital or O&M expenses are forecasted.

Project Title: **Coal Combustion Residual (CCR) Rule**
Project No. 18

Project Description:
The Coal Combustion Residual (CCR) Rule was published in the Federal Register on 4/17/15 and is effective 10/19/15. This rule regulates the disposal of CCR as non-hazardous solid waste, and contains new requirements for CCR landfills and CCR surface impoundments. It also specifies implementation guidelines for compliance. The CCR compliance deadlines vary, with compliance obligations required as early as 10/19/15. The rule is self-implementing, meaning that affected facilities must comply with the new regulations irrespective of whether the rule is adopted by the State of Florida. The rule has specific impacts on the ash landfill, Flue Gas Desulfurization (FGD) lined blowdown ponds and temporary gypsum pad at the Crystal River site. No other DEF operating facilities are impacted by the CCR rule.

Project Accomplishments:
Annual inspections were completed for the FGD Blowdown Ponds and Ash Landfill. Maintenance, vegetation management, and weekly inspections for the FGD Blowdown Ponds and Ash Landfill continue. The groundwater assessment project for the FGD Blowdown Ponds and Ash Landfill continued per the requirements of the rule.

Project Fiscal Expenditures:
2021 estimated O&M expenditures are $752k. Capital forecast is $1.8M.

Project Progress Summary:
Ash Landfill: currently O&M work to remove some accumulated CCR material in the perimeter ditch, also some capital work after that for a new lined basin / ditch area, which will help avoid further accumulation in the future. Expected completion in 2021.

FGD Blowdown Ponds: Dewatering and solids removal from the primary and backup FGD Blowdown Ponds were completed. Pond closure was completed 2020, and alternative source demonstration was completed to address statistically significant increases in certain constituents in groundwater.

Lined sedimentation basin expected to be complete in 2021.

Vegetation Management & Inspection Work: More frequent mowing and inspection work is being performed, to comply with the CCR Rule.

Project Projections:
2022 estimated O&M expenditures are $343k. No capital expenditures are forecasted.

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of the Energy & Demand Allocation % by Rate Class
January 2022 - December 2022

Form 42-6P

Docket No. 20210007-EI
Duke Energy Florida, LLC
Witness: G. P. Dean
Exh. No. __ (GPD-5)

Rate Class	(1) Average 12CP Load Factor at Meter (%)	(2) Sales at Meter (mWh)	(3) Avg 12 CP at Meter (MW) (2)/(8760hrsx(1))	(4) NCP Class Max Load Factor	(5) Delivery Efficiency Factor	(6) Sales at Source (Generation) (mWh) (2)/(5)	(7) Avg 12 CP at Source (MW) (3)/(5)	7(a) Sales at Source (Distrib Svc Only) (mWh)	(8) Class Max MW at Source Level (Distrib Svc) (7a)/(8760hrs/(4))	(9) mWh Sales at Source Energy Allocator (%)	(10) 12CP Demand Transmission Allocator (%)	(11) NCP Distribution Allocator (%)	(12) 12CP & 25% AD Demand Allocator (%)
Residential													
RS-1, RST-1, RSL-1, RSL-2, RSS-1													
Secondary	0.516	21,211,130	4,691.51	0.438	0.9361197	22,658,567	5,011.65	22,658,567	5,907.7	54.164%	64.006%	63.000%	61.546%
General Service Non-Demand													
GS-1, GST-1													
Secondary	0.608	1,018,417	191.23	0.436	0.9361197	1,087,914	204.28	1,087,914	284.6	2.601%	2.609%	3.035%	2.607%
Primary	0.608	18,782	3.53	0.436	0.9759311	19,246	3.61	19,246	5.0	0.046%	0.046%	0.054%	0.046%
Sec Del/Primary Mtr	0.608	42	0.01	0.436	0.9759311	43	0.01	43	0.0	0.000%	0.000%	0.000%	0.000%
Transmission	0.608	2,666	0.50	0.436	0.9859311	2,704	0.51	0	0.0	0.006%	0.006%	0.000%	0.006%
										2.653%	2.662%	3.089%	2.660%
General Service													
GS-2 Secondary	1.000	204,533	23.35	1.000	0.9361197	218,490	24.94	218,490	24.9	0.522%	0.319%	0.266%	0.369%
General Service Demand													
GSD-1, GSDT-1													
Secondary	0.742	11,642,447	1,791.32	0.587	0.9361197	12,436,921	1,913.56	12,436,921	2,419.7	29.730%	24.439%	25.804%	25.762%
Primary	0.742	1,638,508	252.10	0.587	0.9759311	1,678,917	258.32	1,678,917	326.6	4.013%	3.299%	3.483%	3.478%
Secondary Del/ Primary Mtr	0.742	24,351	3.75	0.587	0.9759311	24,952	3.84	24,952	4.9	0.060%	0.049%	0.052%	0.052%
Transm Del/ Primary Mtr	0.742	0	0.00	0.587	0.9759311	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
Transmission	0.742	401,077	61.71	0.587	0.9859311	406,800	62.59	0	0.0	0.972%	0.799%	0.000%	0.843%
SS-1 Primary	0.958	48,108	5.73	0.456	0.9759311	49,294	5.87	49,294	12.4	0.118%	0.075%	0.132%	0.086%
Transm Del/ Transm Mtr	0.958	3,723	0.44	0.456	0.9859311	3,776	0.45	0	0.0	0.009%	0.006%	0.000%	0.007%
Transm Del/ Primary Mtr	0.958	1,546	0.18	0.456	0.9759311	1,585	0.19	0	0.0	0.004%	0.002%	0.000%	0.003%
										34.906%	28.670%	29.471%	30.229%
Curtailable													
CS-2, CST-2, SS-3													
Secondary	1.028	0	0.00	0.358	0.9361197	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
Primary	1.028	62,060	6.89	0.358	0.9759311	63,590	7.06	63,590	20.3	0.152%	0.090%	0.216%	0.106%
SS-3 Primary	2.390	58,185	2.78	0.314	0.9759311	59,620	2.85	59,620	21.7	0.143%	0.036%	0.231%	0.063%
										0.295%	0.127%	0.447%	0.169%
Interruptible													
IS-2, IST-2													
Secondary	0.957	406,762	48.52	0.732	0.9361197	434,520	51.83	434,520	67.7	1.039%	0.662%	0.722%	0.756%
Sec Del/Primary Mtr	0.957	5,152	0.61	0.732	0.9759311	5,279	0.63	5,279	0.8	0.013%	0.008%	0.009%	0.009%
Primary Del / Primary Mtr	0.957	1,171,449	139.72	0.732	0.9759311	1,200,340	143.17	1,200,340	187.1	2.869%	1.828%	1.995%	2.089%
Primary Del / Transm Mtr	0.957	226	0.03	0.732	0.9859311	229	0.03	229	0.0	0.001%	0.000%	0.000%	0.000%
Transm Del/ Transm Mtr	0.957	599,084	71.46	0.732	0.9859311	607,632	72.47	0	0.0	1.453%	0.926%	0.000%	1.057%
Transm Del/ Primary Mtr	0.957	429,008	51.17	0.732	0.9759311	439,588	52.43	0	0.0	1.051%	0.670%	0.000%	0.765%
SS-2 Primary	1.147	13,316	1.32	0.306	0.9759311	13,644	1.36	13,644	5.1	0.033%	0.017%	0.054%	0.021%
Transm Del/ Transm Mtr	1.147	1,250	0.12	0.306	0.9859311	1,268	0.13	0	0.0	0.003%	0.002%	0.000%	0.002%
Transm Del/ Primary Mtr	1.147	44,422	4.42	0.306	0.9759311	45,518	4.53	0	0.0	0.109%	0.058%	0.000%	0.071%
										6.569%	4.171%	2.781%	4.770%
Lighting													
LS-1 (Secondary)	11.683	348,815	3.41	0.479	0.9361197	372,618	3.64	372,618	88.8	0.891%	0.046%	0.947%	0.258%
		39,355,060	7,355.81			41,833,056	7,829.95	40,324,184	9,377.3	100.000%	100.000%	100.000%	100.000%

Notes:

(1) Average 12CP load factor based on load research study filed July 30, 2021
(2) Projected kWh sales for the period January 2022 to December 2022
(3) Calculated: Column 2 / (8,760 hours x Column 1)
(4) NCP load factor based on load research study filed July 30, 2021
(5) Based on system average line loss analysis for 2020
(6) Column 2 / Column 5
(7) Column 3 / Column 5
(7a) Column 6 excluding transmission service
(8) Calculated: Column 7a / (8,760 hours/ Column 4)
(9) Column 6/ Total Column 6
(10) Column 7/ Total Column 7
(11) Column 8/ Total Column 8
(12) (Column 9 x .25) + (Column 10 x .75)

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Environmental Cost Recovery Clause Rate Factors by Rate Class
January 2022 - December 2022

Rate Class		(1) mWh Sales at Source Energy Allocator (%)	(2) 12CP Transmission Demand Allocator (%)	(3) NCP Distribution Allocator (%)	(4) 12CP & 25% AD Demand Allocator (%)	(5) Energy-Related Costs ($)	(6) Transmission Demand Costs ($)	(7) Distribution Demand Costs ($)	(8) Production Demand Costs ($)	(9) Total Environmental Costs ($)	(10) Projected Effective Sales at Meter Level (mWh)	**(11) Environmental Cost Recovery Factors (cents/kWh)**
Residential												
RS-1, RST-1, RSL-1, RSL-2, RSS-1												
	Secondary	54.164%	64.006%	63.000%	61.546%	$3,676,241	($1,401)	($412)	$2,255,317	$5,929,746	21,211,130	**0.028**
General Service Non-Demand												
GS-1, GST-1												
	Secondary										1,018,417	**0.027**
	Primary										18,636	**0.027**
	Transmission										2,613	**0.026**
	TOTAL GS	2.653%	2.662%	3.089%	2.660%	$180,077	($58)	($20)	$97,458	$277,456	**1,039,667**	
General Service												
GS-2	Secondary	0.522%	0.319%	0.266%	0.369%	$35,449	($7)	($1.74)	$13,539.45	$48,980	204,533	**0.024**
General Service Demand												
GSD-1, GSDT-1, SS-1												
	Secondary										11,642,447	**0.025**
	Primary										1,695,388	**0.025**
	Transmission										396,704	**0.025**
	TOTAL GSD	34.906%	28.670%	29.471%	30.229%	$2,369,142	($627)	($193)	$1,107,721	$3,476,043	**13,734,539**	
Curtailable												
CS-2, CST-2, CS-3, CST-3, SS-3												
	Secondary										-	**0.022**
	Primary										119,042	**0.022**
	Transmission										-	**0.022**
	TOTAL CS	0.295%	0.127%	0.447%	0.169%	$19,990	($3)	($3)	$6,177	$26,162	**119,042**	
Interruptible												
IS-2, IST-2, SS-2												
	Secondary										406,762	**0.023**
	Primary										1,646,714	**0.023**
	Transmission										588,548	**0.023**
	TOTAL IS	6.569%	4.171%	2.781%	4.770%	$445,852	($91)	($18)	$174,808	$620,551	**2,642,025**	
Lighting												
LS-1	Secondary	0.891%	0.046%	0.947%	0.258%	$60,455	($1)	($6.19)	$9,438.04	$69,886	348,815	**0.020**
		100.000%	100.000%	100.000%	100.000%	$6,787,207	($2,188)	($654)	$3,664,458	$10,448,824	39,299,750	**0.027**

Notes:

(1) From Form 42-6P, Column 9
(2) From Form 42-6P, Column 10
(3) From Form 42-6P, Column 11
(4) From Form 42-6P, Column 12
(5) Column 1 x Total Energy Jurisdictional Dollars from Form 42-1P, line 5
(6) Column 2 x Total Transmission Demand Jurisdictional Dollars from Form 42-1P, line 5
(7) Column 3 x Total Distribution Demand Jurisdictional Dollars from Form 42-1P, line 5
(8) Column 4 x Total Production Demand Jurisdictional Dollars from Form 42-1P, line 5
(9) Column 5 + Column 6 + Column 7 + Column 8
(10) Projected kWh sales at secondary voltage level for the period January 2022 to December 2022
(11) (Column 9 / Column 10)/10

		(1) Jurisdictional Rate Base Adjusted Retail ($000s)	(2) Cap Ratio	(3) Cost Rate	(4) Weighted Cost	(5) Revenue Requirement Rate	(6) Monthly Revenue Requirement Rate
1	Common Equity	$ 7,302,840	43.96%	9.85%	4.330%	5.80%	0.4833%
2	Long Term Debt	6,603,424	39.75%	4.11%	1.635%	1.63%	0.1358%
3	Short Term Debt	74,501	0.45%	1.66%	0.007%	0.01%	0.0008%
4	Cust Dep Active	182,161	1.10%	2.36%	0.026%	0.03%	0.0025%
5	Cust Dep Inactive	1,888	0.01%			0.00%	0.0000%
6	Invest Tax Cr	215,728	1.30%	7.13%	0.093%	0.12%	0.0100%
7	Deferred Inc Tax	2,230,499	13.43%			0.00%	0.0000%
8	**Total**	**$ 16,611,041**	**100.00%**		**6.09%**	**7.59%**	**0.6325%**

	ITC split between Debt and Equity**:		Ratio	Cost Rate	Ratio	Ratio	Deferred Inc Tax	Weighted ITC	After Gross-up
9	Common Equity	7,302,840	53%	9.85%	5.17%	72.6%	0.09%	0.067%	0.090%
10	Preferred Equity	-	0%				0.09%	0.000%	0.000%
11	Long Term Debt	6,603,424	47%	4.11%	1.95%	27.4%	0.09%	0.025%	0.025%
12	ITC Cost Rate	13,906,264	100%		7.13%			0.093%	0.115%

Breakdown of Revenue Requirement Rate of Return between Debt and Equity:

13	Total Equity Component (Lines 1 and 9)	5.890%	Total Pre-Tax Equity
14	Total Debt Component (Lines 2, 3 , 4 , and 11)	1.695%	Total Debt
15	**Total Revenue Requirement Rate of Return**	7.585%	WACC

Notes:

Effective Tax Rate: 25.345%

Column:

(1) Per Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology
(2) Column (1) / Total Column (1)
(3) Per Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology
Line 6 and Line 12, the cost rate of ITC's is determined under Treasury Regulation section 1.46-6(b)(3)(ii).
(4) Column (2) x Column (3)
(5) For equity components: Column (4) / (1-effective income tax rate/100)
* For debt components: Column (4)
** Line 6 is the pre-tax ITC components from Lines 9 and 11
(6) Column (5) / 12

Duke Energy Florida, LLC

Review of Integrated Clean Air Compliance Plan

Submitted to the
Florida Public Service Commission

April 1, 2021

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Acronyms

BART – Best Available Retrofit Technology

CAIR – Clean Air Interstate Rule

CAMR – Clean Air Mercury Rule

CAVR – Clean Air Visibility Rule

CCR - Coal Combustion Residuals

CO_2 – Carbon Dioxide

CPP – Clean Power Plan

CSAPR – Cross-State Air Pollution Rule

DEF – Duke Energy Florida

ECRC – Environmental Cost Recovery Clause

EPA – Environmental Protection Agency

EGU – Electric Generating Unit

ELG - Effluent Limitation Guidelines

ESP – Electrostatic Precipitator

FDEP – Florida Department of Environmental Protection

FGD – Flue Gas Desulfurization

GHG – Greenhouse Gas

LNB – Low NO_x Burner

MATS – Mercury and Air Toxic Standards

MWh – Megawatt Hour

NAAQS – National Ambient Air Quality Standards

NO_x – Nitrogen Oxides

NPDES – National Pollutant Discharge Elimination System

NSPS - New Source Performance Standards

PAC – Powdered Activated Carbon

Plan D – DEF Integrated Clean Air Compliance Plan

PM – Particulate Matter

ppb – Parts per billion

PSC – Public Service Commission

SCR – Selective Catalytic Reduction

SIP – Site Implementation Plan

SO_2 – Sulfur Dioxide

Executive Summary

In the 2007 Environmental Cost Recovery Clause ("ECRC") Docket (No. 20070007-EI), the Commission approved Duke Energy Florida LLC's ("DEF") updated Integrated Clean Air Compliance Plan (Plan D) as a reasonable and prudent means to comply with the requirements of the Clean Air Interstate Rule ("CAIR") (subsequently replaced by the Cross-State Air Pollution Rule ("CSAPR"), Clean Air Mercury Rule ("CAMR") (subsequently replaced by the Mercury and Air Toxics Standards ("MATS") rule), Clean Air Visibility Rule ("CAVR"), and related regulatory requirements. In its 2007 final Order No. PSC-07-0922-FOF-EI, the Commission also directed DEF to file as part of its ECRC true-up testimony "a yearly review of the efficacy of its Plan D and the cost-effectiveness of DEF's retrofit options for each generating unit in relation to expected changes in environmental regulations." This report provides the required review for 2021.

The primary original components of DEF's 2006 Compliance Plan D included:

Sulfur Dioxide ("SO_2")

- Installation of flue gas desulfurization ("FGD") systems on Crystal River ("CR") Units 4 and 5
- Fuel switching at CR Units 1 and 2 to burn low sulfur coal
- Fuel switching at Anclote Units 1 and 2 to burn low sulfur oil and natural gas
- Purchases of SO_2 allowances

Nitrogen Oxides ("NO_x")

- Installation of low NO_x burners ("LNBs") and selective catalytic reduction ("SCR") systems on CR Units 4 and 5
- Installation of LNBs and separated over-fire air ("SOFA") or alternative NO_x controls at Anclote Units 1 and 2
- Purchase of annual and ozone season NO_x allowances

Mercury

- Installation of FGD and SCR systems at CR Units 4 and 5
- Installation of powdered activated carbon ("PAC") injection on CR Unit 2

As detailed in Docket No. 20070007-EI, DEF decided on Plan D based on a quantitative and qualitative evaluation of the ability of alternative plans to meet environmental requirements, while managing risks and controlling costs. That evaluation demonstrated that Plan D is DEF's most cost-effective alternative to meet applicable regulatory requirements. The Plan was designed to strike a balance between reducing emissions, primarily through the installation of controls on DEF's largest and newest coal units (CR Units 4 and 5) and making strategic use of emission allowance markets.

In accordance with the Commission's final order in Docket No. 20070007-EI, DEF has continued to review the efficacy of Plan D and the cost-effectiveness of retrofit options in relation to expected changes in environmental regulations. With regard to efficacy, Plan D remains the cornerstone of DEF's efforts to comply with applicable air quality regulations in a cost-effective manner.

As indicated in previous ECRC filings, the U.S. Court of Appeals for the District of Columbia ("D.C. Circuit") stayed the effect of CSAPR (proposed by the U.S. Environmental Protection Agency ("EPA") to replace CAIR) leaving CAIR in effect until the court completed its review of CSAPR. In August 2012, the D.C. Circuit vacated CSAPR in its entirety, and in January 2013, the court denied EPA's petition for rehearing. On April 29, 2014, the U.S. Supreme Court reversed the D.C. Circuit's decision and upheld the CSAPR. EPA subsequently petitioned the D.C. Circuit to reinstate CSAPR, making it effective January 1, 2015. The court agreed with EPA and approved its petition.

Additionally, on February 16, 2012, EPA issued MATS to replace the vacated CAMR for emissions from coal- and oil-fired electric generating units ("EGUs"), including, potentially, DEF's Anclote Units 1 and 2, Suwannee Units 1, 2, and 3, and CR Units 1, 2, 4 and 5. The following summarizes the results of DEF's MATS compliance analyses for these units:

<u>Anclote Units 1 & 2</u>: DEF determined that the most cost-effective option for Anclote Units 1 and 2 was conversion to fire 100% natural gas rather than installation of emission controls to comply with MATS. The Commission approved DEF's petition for ECRC recovery of costs associated with the Anclote Conversion Project in Docket No. 20120103-EI.

<u>Suwannee Units 1, 2 & 3</u>: DEF determined that no further modifications were needed on Suwannee Units 1, 2 and 3 as these units were already capable of operating on 100% natural gas.

<u>CR Units 4 & 5</u>: DEF determined that the existing electrostatic precipitators ("ESPs"), FGDs, and SCRs at CR Units 4 and 5 would provide sufficient control for MATS compliance under typical conditions. DEF also determined that chemical injection systems would be required

to mitigate mercury re-emissions from the FGDs. On December 15, 2014, DEF requested a one-year extension to allow time for installation of additional mercury control systems. On March 12, 2015, the Florida Department of Environmental Protection ("FDEP") authorized a one-year extension (to April 16, 2016) for all mercury-related MATS requirements on CR Units 4 and 5; the units have operated in compliance with the Standards since that time.

CR Units 1 & 2: DEF determined that the use of alternative coals (along with dry sorbent injection, PAC injection, and ESP enhancements) was a feasible and cost-effective strategy to allow these units to continue running for a limited period of time in compliance with MATS and Best Available Retrofit Technology ("BART") requirements until new generation could be built. This plan was approved by the Commission in Order No. PSC-2014-0173-PAA-EI (April 17, 2014). On February 6, 2014, the FDEP granted a one-year extension (to April 16, 2016) for all MATS requirements on CR Units 1 and 2; the units were operated in compliance with the Standards since that time. CR Units 1 and 2 were retired from service on December 31, 2018.

Although EPA has begun implementation of a regulatory approach to reduce greenhouse gas ("GHG") emissions through the Clean Air Act, there currently are no GHG emission standards applicable to DEF's existing units. Moreover, there are still no retrofit options commercially available to reduce carbon dioxide ("CO_2") emissions from fossil fuel-fired EGUs. The Company will continue to monitor and update the Commission on EPA's efforts to establish emission guidelines to address GHG from existing power plants under Section 111(d) of the federal Clean Air Act and whether changes to EPA's approach occur.

DEF is confident that the emission controls installed pursuant to Plan D, along with compliance strategies discussed further in this Plan, will enable the Company to achieve and maintain compliance with all applicable environmental regulations in a cost-effective manner.

I. Introduction

In its final order in the 2007 ECRC Docket (No. 20070007-EI), the Commission approved DEF's updated Integrated Clean Air Compliance Plan (Plan D) as a reasonable and prudent means to comply with the requirements of CAIR, CAMR, CAVR and related regulatory requirements. In *In re Environmental Cost Recovery Clause*, Order No. PSC-2007-0922-FOF-EI, p. 8 (Nov. 16, 2007), the Commission specifically found that "PEF's [now DEF's] updated Integrated Clean Air Compliance Plan represents the most cost-effective alternative for achieving and maintaining compliance with CAIR, CAMR, and CAVR, and related regulatory requirements, and it is reasonable and prudent for DEF to recover prudently incurred costs to implement the plan." *Id*. The Commission also directed DEF to file as part of its ECRC true-up testimony "a yearly review of the efficacy of its Plan D and the cost-effectiveness of [DEF's] retrofit options for each generating unit in relation to expected changes in environmental regulations." *Id*. The purpose of this report is to provide the required review for 2020.

II. Regulatory Background

The CAIR and CAVR programs required DEF and other utilities to significantly reduce emissions of SO_2 and NO_x. CAIR contemplated emission reductions in incremental phases, in which Phase I began in 2009 for NO_x and in 2010 for SO_2. Phase II was scheduled to begin in 2015 for both NO_x and SO_2. As noted later in this Plan, CAIR was remanded by the courts in 2008, but remained in place through 2014 while the EPA worked on development and implementation of an acceptable replacement rule. Following resolution of litigation, the replacement rule, CSAPR, took effect on January 1, 2015, and in 2016 was revised to exclude Florida. The CAVR, designed to improve visibility in Class I areas, remains in effect and the status of the BART requirements under CAVR affecting DEF is provided in part D of this section of this Plan. The CAMR originally required reduction of mercury emissions at a system level and installation of mercury monitors. As discussed later in this Plan, CAMR was vacated in early 2008 and in lieu of CAMR, EPA published a final MATS rule on February 16, 2012.

In March 2006, the Company submitted a report and supporting Testimony presenting its integrated plan for complying with the CAIR, CAVR, and CAMR, as well as the process the Company used to evaluate alternative plans, to the Commission. The analysis included an examination of the projected emissions associated with several alternative plans and a comparison of economic impacts, in terms of cumulative present value of revenue requirements. The Company's Integrated Clean Air Compliance Plan, designated as Plan D, was found to be the most cost-effective compliance plan for CAIR, CAMR, and CAVR from among five alternative plans.

In June 2007, the Company submitted an updated report and supporting testimony summarizing the status of the Plan and an updated economic analysis incorporating certain Plan revisions necessitated by changed circumstances. Consistent with the approach utilized in 2006, the Company performed a quantitative evaluation to compare the ability of modified alternative plans to meet environmental requirements, while managing risks and controlling costs. That evaluation demonstrated that Plan D, as revised, is the Company's most cost-effective alternative to meet applicable regulatory requirements. Based on that analysis, the Commission approved Plan D as reasonable and prudent, and held that the Company should recover prudently incurred costs of implementing the Plan. In each subsequent ECRC docket, DEF has submitted its annual review of the Integrated Clean Air Compliance Plan for Commission review.

A. Status of CAIR and CSAPR

In July 2008, the D.C. Circuit issued a decision vacating CAIR in its entirety. *North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir. 2008). However, the Court subsequently decided to remand CAIR without vacatur, thereby leaving the rule and its compliance obligations in place until EPA revises or replaces CAIR. *North Carolina v. EPA*, 550 F.3d 1176 (D.C. Cir. 2008). EPA adopted the CSAPR to replace the CAIR by publication in the *Federal Register* in August 2011. *See* 76 Fed. Reg. 48,208 (Aug. 8, 2011).

In Order No. PSC-2011-0553-FOF-EI, issued in Docket No. 20110007-EI on December 7, 2011, the Commission addressed the impact of CSAPR on the Company's recovery of NO_x emission allowance costs. Because CSAPR would no longer allow the Company to use NO_x allowances previously obtained under CAIR for compliance effective January 1, 2012, the Commission established a regulatory asset to allow the Company to recover the costs of its remaining NO_x allowance inventory over a three-year amortization period. However, on December 30, 2011, the D.C. Circuit stayed CSAPR, leaving CAIR in effect until the court completed its review of the new rule. Thus, the Company continued to maintain its NO_x allowance inventory in order to comply with CAIR. Pursuant to the stipulation approved in Order No. PSC-

2011-0553-FOF-EI, the Company continued to expense NO_x allowance costs incurred to comply with CAIR based on actual usage consistent with current practice. In August 2012, the D.C. Circuit vacated CSAPR in its entirety, and in January 2013, the court denied EPA's petition for rehearing. *See EME Homer City Generation, L.P. v. EPA*, 696 F.3d 7 (D.C. Cir. 2013). The EPA subsequently appealed the court's vacatur to the U.S. Supreme Court and on April 29, 2014, the Supreme Court overturned the D.C. Circuit's decision vacating CSAPR and remanded the case back to the lower court for further action. On June 26, 2014, the EPA requested that the court lift the stay of the CSAPR and allow it to be implemented, under a revised schedule, beginning January 1, 2015. This request was granted on October 23, 2014, and the CSAPR went into effect on January 1, 2015, replacing the CAIR. On July 28, 2015, the D.C. Circuit determined that EPA failed to cost justify a number of Phase 2 emission allowance budgets for certain states, including Florida, citing they were more stringent than necessary to achieve air compliance in downwind states, and held the Phase 2 NO_x allowance allocations invalid. Finally, on November 17, 2015, EPA proposed a revised CSAPR. EPA proposed to remove Florida from the CSAPR program, beginning with the 2017 ozone season.

On September 7, 2016, EPA finalized its CSAPR Update rule and eliminated Florida, South Carolina, and North Carolina from the CSAPR ozone season program based on modeling which shows that NO_x emissions from these states do not significantly contribute to ozone nonattainment in any downwind state. DEF sources in Florida are no longer subject to any CSAPR NO_x emission limitations, as of the beginning of 2017.

B. Vacatur of CAMR and Adoption of MATS

In February 2008, the D.C. Circuit Court vacated CAMR and rejected EPA's delisting of coal-fired EGUs from the list of emission sources that are subject to Section 112 of the Clean Air Act. *See New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008). As a result, in lieu of CAMR, EPA was required to adopt new emissions standards for control of various hazardous air pollutant emissions from coal-fired EGUs. *Id*. EPA issued its proposed rule to replace CAMR on March 16, 2011, with publication following in the *Federal Register* on May 3, 2011. *See* 76 Fed. Reg. 24976 (May 3, 2011). On February 16, 2012, EPA published the final rule which established new MATS limits for emissions of various metals and acid gases from both coal- and oil-fired EGUs. Compliance generally was required to be achieved within three years of EPA's adoption of MATS (i.e., April 16, 2015), although the Clean Air Act authorizes permitting authorities to grant one-year compliance extensions in certain circumstances. On June 29, 2015, the U.S. Supreme Court remanded the MATS rule to the D.C. Circuit, finding that the EPA insufficiently considered costs in determining that it is "appropriate and necessary" to regulate mercury from power plants. On December 15, 2015, the D.C. Circuit remanded the MATS rule to EPA without vacatur, and EPA committed to completing its consideration of cost by April 16, 2016. On March 3, 2016, the U.S. Supreme Court denied a request for a stay of the MATS rule while the EPA completes it cost consideration, thus the MATS rule remained in effect pending the cost consideration process. On March 18, 2016, a coalition of 20 states led by Michigan petitioned the Court for a writ of certiorari asking the Court to declare whether an administrative rule promulgated without statutory authority may be left in effect by a reviewing court during the pendency of its review. *See State of Mich., et al. v. EPA*, Pet. for Writ of Cert. to U.S. Sup. Ct. (filed Mar. 18, 2016). On April 14, 2016 EPA issued a final finding that it is appropriate and necessary to set standards for emissions of air toxics from coal and oil-fired power plants. This finding responded to the decision by the U.S. Supreme Court that EPA must consider cost in the appropriate and necessary finding supporting MATS. This finding was challenged.

On February 7, 2019, the EPA proposed a revision to its response to the U.S. Supreme Court decision in *Michigan v. EPA* which held that the EPA erred by not considering cost in its determination that regulation under section 112 of the Clean Air Act of hazardous air pollutant emissions from coal- and oil-fired electric utility steam generating units is appropriate and necessary. On May 22, 2020, EPA published a reconsideration of the appropriate and necessary finding for the MATS, correcting flaws in the 2016 supplemental cost finding. However, EPA is not removing coal- and oil-fired EGUs from the list of affected source categories for regulation under section 112 of the CAA, so the MATS rule remains in effect. This proposal is currently under review.

In the 2011 ECRC docket, the Commission recognized that EPA's adoption of MATS for EGUs would require the Company to modify its Integrated Clean Air Compliance Plan. See Order No. PSC-2011-0553-FOF-EI, at 11. Accordingly, consistent with the Commission's expectation that utilities "take steps to control the level of costs that must be incurred for environmental compliance," Order No. PSC-2008-0775-FOF-EI, at 7, the Commission approved the Company's request to recover costs incurred to assess EPA's proposed rule, prepare comments to EPA and develop compliance strategies within the aggressive regulatory timeframes proposed by EPA.

C. Greenhouse Gas Regulation

In 2007, then-Governor Crist issued Executive Order 07-127 directing the FDEP to promulgate regulations requiring reductions in utility CO_2 emissions. In addition, the 2008 Florida Legislature enacted legislation authorizing FDEP to adopt rules establishing a cap-and-trade program and requiring the FDEP to submit any such rules for legislative review and ratification. However, the FDEP did not adopt any cap-and-trade rules, and the Legislature subsequently repealed the 2008 law. Likewise, although a number of bills that would regulate GHG emissions have been introduced to Congress over the past several years, none have become law. In the meantime, the EPA began implementing a regulatory approach to reducing GHG emissions through the Clean Air Act. At this time, however, there are no GHG emission standards applicable to DEF's existing generating units. Moreover, there are still no retrofit options commercially available to reduce CO_2 emissions from fossil fuel-fired electric generating units such as CR Units 4 and 5, which are the primary focus of DEF's compliance plan. To date, there are very limited large-scale commercial carbon capture and storage technology demonstrations on electric utility units. Until numerous technological, regulatory, and liability issues are resolved, it will be impossible to determine whether carbon capture and storage would be a technically-feasible or cost-effective means of complying with a CO_2 regulatory regime. Moreover, replacing coal-fired generation from CR Units 4 and 5 with lower CO_2-emitting natural gas-fired combined cycle generation is not a viable option at this late date, particularly given the fact that DEF has placed in service Plan D components.

On June 25, 2013, then-President Obama issued a Presidential Memorandum directing the EPA to establish GHG emission guidelines for existing power plants under Section 111(d) of the Clean Air Act. The Presidential Memorandum directed the EPA to issue proposed GHG standards, regulations, or guidelines, as appropriate, for existing power plants by no later than June 1, 2014, and issue final standards, regulations or guidelines, as appropriate, by no later than June 1, 2015. In addition, the Presidential Memorandum directed the EPA to include a requirement in the new regulations that states submit State Implementation Plans ("SIPs") to implement the new guidelines by no later than June 30, 2016.

On August 3, 2015, the EPA released the final New Source Performance Standards ("NSPS") for CO_2 emissions from existing fossil fuel-fired EGUs (also known as the Clean Power Plan or "CPP"). The final CPP established state-specific emission goals; for Florida, the goals would begin a phased approach in 2022, ending with a rate goal of 919 lb. CO_2/MWh annual average for the period 2030 and beyond. Alternatively, the state was able to adopt a mass emissions approach culminating in a 2030 target of 105,094,704 tons (existing units) or 106,641,595 tons (existing plus new units). The final CPP was challenged in the D.C. Circuit by 27 states and a number of industry groups. Oral argument occurred on September 27, 2016. The D.C. Circuit subsequently issued a stay of the litigation. Previously, on February 9, 2016, the U.S. Supreme Court had placed a stay on the CPP until such time that all litigation is completed.

Also, on August 3, 2015, the EPA released the final NSPS for CO_2 emissions from new, modified and reconstructed fossil fuel-fired EGUs. The rule included emission limits of 1,400 lb. CO_2/MWh for new coal-fired units and 1,000 lb. CO_2/MWh for new natural gas combined-cycle units. This rule was also challenged in the D.C. Circuit. The D.C. Circuit issued an order suspending this litigation pending a review of the rule by EPA.

On March 28, 2017, then-President Trump signed an Executive Order ("EO") entitled "Promoting Energy Independence and Economic Growth." The EO directs federal agencies to "immediately review existing regulations that potentially burden the development or use of domestically produced energy resources and appropriately suspend, revise, or rescind those that unduly burden the development of domestic energy resources." The EO specifically directed the EPA to review the following rules and determine whether to suspend, revise, or rescind those rules:

- The final CO_2 emission standards for existing power plants ("CPP");
- The final CO_2 emission standards for new power plants ("CO_2 NSPS");
- The proposed Federal Plan and Model Trading Rules that accompanied the CPP.

In response to the EO, the Department of Justice filed motions with the D.C. Circuit Court to stay the litigation of both the CPP and the CO_2 NSPS rules while each is reviewed by EPA. The EO did not change the current status of the CPP which was under a legal hold by the U.S. Supreme Court. With regard to the CO_2 NSPS, that rule will remain in effect pending the outcome of EPA's review. On December 6, 2018, EPA proposed to revise the New Source Performance Standards (NSPS) for greenhouse gas emissions from new, modified, and reconstructed fossil fuel-fired power plants. After further analysis and review, EPA proposes to determine that the best system of emission reduction ("BSER") for newly constructed coal-fired units, is the most efficient demonstrated steam cycle in combination with the best operating practices. EPA did not propose to amend the standards of performance for newly constructed or reconstructed stationary combustion turbines. In January 2021, EPA issued a clear framework for determining when standards are appropriate for GHG emissions from stationary source categories under Clean Air Act (CAA) section 111(b)(1)(A). EPA did not take final action to revise the BSER in the 2018 proposal.

On October 16, 2017, the EPA published a proposal to announce its intention to repeal the CPP. The proposal also requested public comment on the proposed rule. The EPA held public hearings on November 28 and 29, 2017, in Charleston, West Virginia, and extended the public comment period until January 16, 2018. In response to numerous requests for additional opportunities for the public to provide oral testimony on the proposed rule in more than one location, the EPA conducted three listening sessions, and extended the public comment period until April 26, 2018.

On December 28, 2017, EPA published an Advanced Notice of Proposed Rulemaking ("ANPR") to solicit information from the public as the agency considered proposing emission guidelines to limit GHG emissions from existing EGUs. EPA also "solicited information on the proper respective roles of the state and federal governments in the process, as well as information on systems of emission reduction that are applicable at or to an existing EGU, information on compliance measures, and information on state planning requirements under the Clean Air Act."

On June 19, 2019, EPA issued the Affordable Clean Energy rule ("ACE"), an effort to provide existing coal-fired electric utility generating units, or EGUs, with achievable and realistic standards for reducing greenhouse gas (GHG) emissions. This action was finalized in conjunction with two related, but separate and distinct rulemakings: (1) The repeal of the Clean Power Plan (CPP) and (2) Revised implementing regulations for ACE, ongoing emission guidelines, and all future emission guidelines for existing sources issued under the authority of Clean Air Act (CAA) section 111(d). On January 19, 2021, the court vacated the ACE rule and remanded it back to EPA. Vacatur means that the rule will no longer be in effect once the Mandate is issued; the Mandate is the court's directive to enforce its decision. On February 22, 2021, the court granted EPA's motion to withhold issuance of the mandate with respect to the vacatur of the Clean Power

Plan Repeal Rule until the EPA responds to the court's remand in a new rulemaking action. No party filed for Rehearing regarding the court's January 19th decision. Accordingly, on March 5, 2021, the court issued the Partial Mandate to EPA, officially vacating the ACE rule, but withholding the mandate regarding the CPP repeal. Currently, neither the ACE rule nor Clean Power Plan rule are in effect. The parties have until April 19, 2021, to ask the Supreme Court to take the case.

D. Status of BART Requirements under CAVR

In 2009, the FDEP issued a permit imposing BART requirements for particulate matter ("PM") emissions from CR Units 1 and 2. The 2009 permit did not impose BART requirements for SO_2 and NO_x emissions because, at the time, the EPA assumed that compliance with CAIR would satisfy BART requirements for SO_2 and NO_x. Following the proposed adoption of CSAPR, in early 2012, the EPA revised its previous determination to replace the "CAIR satisfies BART" assumption with "CSAPR satisfies BART." In late 2011, CSAPR was vacated (although later re-instated – see part A above), leaving CAIR in effect and resulting in confusion regarding the ability to rely on CAIR (or CSAPR) to satisfy BART requirements. As a result, in 2012, the Company worked with the FDEP to develop and finalize air construction permits to address SO_2 and NO_x emissions from CR Units 1 and 2 in support of FDEP's development of a revised Regional Haze SIP to address CAVR requirements for SO_2 and NO_x. As discussed in the Company's 2013 Integrated Clean Air Compliance Plan, the FDEP subsequently submitted to EPA a revised Regional Haze SIP containing unit-specific determinations for SO_2 and NO_x, including the new permit requirements for CR Units 1 and 2. EPA formally approved the FDEP's revised Regional Haze SIP in August 2013. *See* 78 Fed Reg. 53250 (August 29, 2013). Although third parties initially petitioned for review of EPA's approval in the U.S. Court of Appeals for the Eleventh Circuit, the Petition was subsequently withdrawn, and the SIP approval remains in place. CR Units 1 and 2 were retired from service on December 31, 2018.

The permits call for the installation of Dry FGD and SCR no later than January 1, 2018, or within 5 years of the effective date of the EPA's approval of the Florida Regional Haze SIP, whichever is later, or alternatively the discontinuation of the use of coal in CR Units 1 and 2 by December 31, 2020. DEF ultimately selected the latter of the two options. CR Units 1 and 2 were retired from service on December 31, 2018.

E. Status of National Ambient Air Quality Standards (NAAQS)

The EPA and FDEP worked to implement the 2010 one-hour NAAQS for SO_2. In mid-2013, the EPA finalized nonattainment designations for two small areas in Florida outside of DEF's service territory (one in Nassau County, one in Hillsborough County) based on existing monitoring data. The EPA deferred making any area designations (attainment, nonattainment, or unclassifiable) for the remainder of the state. On August 21, 2015, the EPA published a final rule that describes requirements for additional ambient air quality monitoring and/or modeling that will be used to determine future rounds of area designations. Under the rule, the EPA made nonattainment designations in 2017 for modeled areas, and in 2020 will make designations for monitored areas. Based on the EPA modeling protocol, the FDEP modeled the area surrounding the Crystal River facility and determined that future operation will not cause a nonattainment issue. This finding was provided to EPA on January 13, 2017, as part of the FDEP's Data Requirements Rule package submittal. On August 22, 2017, EPA issued the Intended Area Designation document, which did not concur with FDEP's recommendation, and outlined EPA's intent to identify an area in Citrus County near the Crystal River Power Plant as nonattainment with the SO2 ambient standard. FDEP provided additional updated information, and on December 21, 2017, EPA issued the final Third Round of SO2 Designations document designating the area around Crystal River as 'unclassifiable' rather than 'nonattainment.' In early 2018, this designation was upgraded to 'attainment,' based on the results of the 2017 full-year data.

In 2010, EPA also revised its NO_2 NAAQS to implement a new one-hour standard. At this time, however, DEF does not anticipate that the new standard will impact compliance measures at DEF facilities.

On October 1, 2015, the EPA issued a revised NAAQS for ambient ozone, changing the standard to 70 parts per billion (ppb) averaged over 8 hours from the previous level of 75 ppb. There are currently no nonattainment areas with respect to the revised standard in Florida; therefore, DEF does not anticipate an impact on its compliance measures.

III. DEF's Integrated Clean Air Compliance Plan

The Company's original compliance plan (Plan D) will continue to help it meet applicable environmental requirements by striking a balance between reducing emissions, primarily through installation of controls on its largest and newest coal units (CR Units 4 and 5). While the original plan made strategic use of the allowance markets to comply with CSAPR requirements, this is no longer necessary as discussed in Section II.A of this document. The controls installed in accordance with Plan D will continue to be the cornerstone of DEF's compliance strategy with the adoption of MATS and other ongoing regulatory efforts. Specific components of the Plan are summarized below.

A. FGD Systems

The most significant component of DEF's Integrated Clean Air Compliance Plan is the installation of FGD systems, also known as wet scrubbers, on CR Units 4 and 5 to comply with CAIR, Title IV of the Clean Air Act, and other SO_2 control requirements in DEF's air permits for these units. The FGDs also reduce mercury and acid gasses and, therefore, are a key component of DEF's MATS compliance strategy. In particular, the co-benefits of the FGDs and SCRs reduce mercury emissions by 90-95% under typical conditions.

B. SCR & Other NO_x Controls

The primary component of DEF's NO_x compliance plan is the installation of LNBs and SCR systems on CR Units 4 and 5. These controls enable DEF to comply with CAIR/CSAPR and other NO_x control requirements included in its air permits for the units. As discussed above, the SCRs also help achieve MATS requirements for mercury.

DEF has taken strategic advantage of CAIR's cap-and-trade feature by purchasing some annual and ozone season NO_x allowances; however, as explained above, the court stay of the CSAPR was lifted, and the rule went into effect replacing CAIR on January 1, 2015. Under the CSAPR, the State of Florida was only affected by the ozone season requirements of the rule, which applied from May through September. Beginning in 2017, the entire state of Florida was removed from the requirements to comply with the CSAPR. Consequently, DEF has NO_x CAIR emission allowances that cannot be used to comply with the CSAPR. DEF established a regulatory asset to recover the costs of its remaining NO_x CAIR emission allowance inventory over a three-year amortization period beginning January 2015 in accordance with Order No. PSC-2011-0553-FOF-EI.

C. Additional MATS Compliance Strategies

DEF determined that the most cost-effective option for its Anclote Units 1 and 2 was conversion to fire 100% natural gas rather than installation of emission controls to comply with MATS. This was approved by the Commission in Docket 20120103-EI.

Suwannee Units 1, 2 and 3 operated exclusively on natural gas and, therefore, were not subject to MATS requirements. At the end of 2016, these units were retired.

DEF utilizes ESP, FGD, and SCR systems as the primary MATS control technologies for CR Units 4 and 5. In addition, DEF has installed chemical injection systems to mitigate mercury re-emissions from the FGDs.

For CR Units 1&2, DEF determined that the use of alternative coals (along with dry sorbent injection, PAC injection, and ESP enhancements) was a feasible and cost-effective strategy to allow these units to continue running for a limited period of time in compliance with MATS and BART requirements until new generation can be built. This plan was approved by the Commission in Order No. PSC-2014-0173-PAA-EI (April 17, 2014). CR Units 1 and 2 were retired from service on December 31, 2018.

D. Visibility Requirements

DEF operated four units that are potentially subject to BART under CAVR: Anclote Units 1 and 2 and CR Units 1 and 2. Based on modeling of air emissions from Anclote Units 1 and 2, those units are exempt from BART for PM. Because the modeling results for CR Units 1 and 2 showed visibility impacts at or above regulatory threshold levels, DEF obtained a BART permit in 2009 for PM for those units. This permit established a combined BART PM emission standard for Crystal River Units 1 and 2 that required demonstration of compliance by October 1, 2013. This deadline was met, and the units operated in compliance with the permit which was effective on January 1, 2014. As discussed above, in 2012, FDEP issued air construction permits addressing SO_2 and NO_x requirements for CR Units 1 and 2 in support of FDEP's development of a revised Regional Haze SIP. These units were also subject to the Reasonable Further Progress ("Beyond BART") requirements under CAVR. As presented in the Company's petition approved in Order PSC-2014-0173-PAA-EI, DEF determined that the use of alternative coals with installation of less expensive pollution controls would provide a cost-effective means for it to continue operating CR

Units 1 and 2 in compliance with MATS and CAVR for a limited time until replacement generation can be constructed. CR Units 1 and 2 were retired from service on December 31, 2018.

IV. Efficacy of DEF's Plan

A. Project Milestones

DEF completed installation of Plan D's controls on CR Units 4 and 5 as contemplated in prior ECRC filings. CR Units 4 and 5 FGD and SCR projects are now in-service, and targeted environmental benefits have been met. In addition to reducing SO_2 and NO_x emissions, the FGDs and SCRs have the combined effect of reducing mercury and other emissions regulated by MATS. DEF installed mercury re-emission control systems in 2015 and has demonstrated compliance with the applicable MATS requirements for CR Units 4 and 5.

The Commission approved DEF's Need Petition in Docket No. 20140110-EI to construct the Citrus County Combined Cycle Units which became commercially available in 2018 and allowed for the retirement of coal-fired CR Units 1 and 2. DEF installed pollution controls on CR Units 1 and 2 to allow for continued operation in compliance with MATS and BART until the Citrus units became operational. CR Units 1 and 2 were retired from service on December 31, 2018. Targeted environmental benefits have been met.

Anclote Units 1 and 2 were converted to fire 100% natural gas in 2013. Necessary upgrades to the forced draft fans were completed in 2014 in order to maintain unit output. Targeted environmental benefits have been met.

B. Projects

CR Units 4 and 5 FGD and SCR projects are now in-service, and the targeted environmental benefits have been met. The Anclote units have been converted to fire 100% natural gas. DEF operated CR Units 1 and 2 in compliance with BART and MATS requirements as outlined in Order No. PSC-2014-0173-PAA-EI until their retirement.

V. Conclusion

DEF has completed installation of the emission controls contemplated in its approved Plan D on time and within budget. The FGD and SCR systems at CR Units 4 and 5 have enabled DEF to comply with CAIR, and subsequently the CSAPR requirements and will continue to be the cornerstone of DEF's integrated air quality compliance strategy for years to come. DEF is confident that Plan D, along with the other compliance strategies discussed in the document, has enabled the Company to achieve and maintain compliance with applicable regulations, including MATS, in a cost-effective manner.

INDEX

TAMPA ELECTRIC COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE

FINAL TRUE-UP AMOUNT FOR THE PERIOD OF JANUARY 2020 THROUGH DECEMBER 2020

FORMS 42-1A THROUGH 42-9A

Form 42 - 1A

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020
(in Dollars)

Line		Period Amount
1.	End of Period Actual True-Up for the Period January 2020 to December 2020 (Form 42-2A, Lines 5 + 6 + 10)	($3,603,985)
2.	Actual/Estimated True-Up Amount Approved for the Period January 2020 to December 2020 (Order No. PSC-2020-0433-FOF-EI)	($7,841,176)
3.	Final True-Up to be Refunded/(Recovered) in the Projection Period January 2020 to December 2020 (Lines 1 - 2)	$4,237,191

Form 42 - 2A

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Current Period True-Up Amount
(in Dollars)

Line	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1. ECRC Revenues (net of Revenue Taxes)	$3,526,547	$3,344,653	$3,299,802	$3,727,610	$3,712,808	$4,312,993	$4,857,739	$4,981,456	$4,692,523	$4,364,942	$4,085,145	$3,542,527	$48,448,746
2. True-Up Provision	542,054	542,054	542,054	542,054	542,054	542,054	542,054	542,054	542,054	542,054	542,054	542,055	6,504,649
3. ECRC Revenues Applicable to Period (Lines 1 + 2)	4,068,601	3,886,707	3,841,856	4,269,664	4,254,862	4,855,047	5,399,793	5,523,510	5,234,577	4,906,996	4,627,199	4,084,582	54,953,395
4. Jurisdictional ECRC Costs													
a. O & M Activities (Form 42-5A, Line 9)	738,601	332,017	1,464,995	2,638,880	1,012,431	2,176,969	1,915,644	180,958	1,398,973	1,189,367	334,852	995,500	14,379,187
b. Capital Investment Projects (Form 42-7A, Line 9)	3,725,028	3,714,545	3,704,392	3,694,361	3,684,230	3,674,442	3,691,189	3,681,542	3,673,518	3,665,880	3,657,410	3,657,152	44,223,689
c. Total Jurisdictional ECRC Costs	4,463,629	4,046,562	5,169,387	6,333,241	4,696,661	5,851,411	5,606,833	3,862,500	5,072,491	4,855,247	3,992,262	4,652,652	58,602,876
5. Over/(Under) Recovery (Line 3 - Line 4c)	(395,028)	(159,855)	(1,327,531)	(2,063,577)	(441,799)	(996,364)	(207,040)	1,661,010	162,086	51,749	634,937	(568,070)	(3,649,482)
6. Interest Provision (Form 42-3A, Line 10)	14,034	12,261	12,474	5,434	236	214	153	171	166	115	145	94	45,497
7. Beginning Balance True-Up & Interest Provision	6,504,649	5,581,601	4,891,953	3,034,842	434,645	(548,972)	(2,087,176)	(2,836,117)	(1,716,990)	(2,096,792)	(2,586,982)	(2,493,954)	6,504,649
a. Deferred True-Up from January to December 2019 (Order No. PSC-2020-0433-FOF-EI)	**3,987,915**	3,987,915	3,987,915	3,987,915	3,987,915	3,987,915	3,987,915	3,987,915	3,987,915	3,987,915	3,987,915	3,987,915	3,987,915
8. True-Up Collected/(Refunded) (see Line 2)	(542,054)	(542,054)	(542,054)	(542,054)	(542,054)	(542,054)	(542,054)	(542,054)	(542,054)	(542,054)	(542,054)	(542,055)	(6,504,649)
9. End of Period Total True-Up (Lines 5+6+7+7a+8)	9,569,516	8,879,868	7,022,757	4,422,560	3,438,943	1,900,739	1,151,798	2,270,925	1,891,123	1,400,933	1,493,961	383,930	383,930
10. Adjustment to Period True-Up Including Interest	0	0	0	0	0	0	0	0	0	0	0	0	0
11. End of Period Total True-Up (Lines 9 + 10)	$9,569,516	$8,879,868	$7,022,757	$4,422,560	$3,438,943	$1,900,739	$1,151,798	$2,270,925	$1,891,123	$1,400,933	$1,493,961	$383,930	$383,930

Form 42 - 3A

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Interest Provision
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Beginning True-Up Amount (Form 42-2A, Line 7 + 7a + 10)	$10,492,564	$9,569,516	$8,879,868	$7,022,757	$4,422,560	$3,438,943	$1,900,739	$1,151,798	$2,270,925	$1,891,123	$1,400,933	$1,493,961	
2.	Ending True-Up Amount Before Interest	9,555,482	8,867,607	7,010,283	4,417,126	3,438,707	1,900,525	1,151,645	2,270,754	1,890,957	1,400,818	1,493,816	383,836	
3.	Total of Beginning & Ending True-Up (Lines 1 + 2)	20,048,046	18,437,123	15,890,151	11,439,883	7,861,267	5,339,468	3,052,384	3,422,552	4,161,882	3,291,941	2,894,749	1,877,797	
4.	Average True-Up Amount (Line 3 x 1/2)	10,024,023	9,218,562	7,945,076	5,719,942	3,930,634	2,669,734	1,526,192	1,711,276	2,080,941	1,645,971	1,447,375	938,899	
5.	Interest Rate (First Day of Reporting Business Month)	1.71%	1.64%	1.56%	2.21%	0.06%	0.08%	0.11%	0.12%	0.13%	0.07%	0.10%	0.14%	
6.	Interest Rate (First Day of Subsequent Business Month)	1.64%	1.56%	2.21%	0.06%	0.08%	0.11%	0.12%	0.13%	0.07%	0.10%	0.14%	0.10%	
7.	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	3.35%	3.20%	3.77%	2.27%	0.14%	0.19%	0.23%	0.25%	0.20%	0.17%	0.24%	0.24%	
8.	Average Interest Rate (Line 7 x 1/2)	1.675%	1.600%	1.885%	1.135%	0.070%	0.095%	0.115%	0.125%	0.100%	0.085%	0.120%	0.120%	
9.	Monthly Average Interest Rate (Line 8 x 1/12)	0.140%	0.133%	0.157%	0.095%	0.006%	0.008%	0.010%	0.010%	0.008%	0.007%	0.010%	0.010%	
10.	Interest Provision for the Month (Line 4 x Line 9)	$14,034	$12,261	$12,474	$5,434	$236	$214	$153	$171	$166	$115	$145	$94	$45,497

Form 42 - 4A

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Variance Report of O & M Activities
(In Dollars)

Line		(1) Actual	(2) Actual/Estimated Projection	(3) Variance Amount	(4) Percent
1.	Description of O&M Activities				
	a. Big Bend Unit 3 Flue Gas Desulfurization Integration	$171,713	$280,339	($108,626)	-38.7%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	-	-	-	0.0%
	c. SO_2 Emissions Allowances	19	(18)	37	-209.2%
	d. Big Bend Units 1 & 2 FGD	24,465	138,950	(114,486)	-82.4%
	e. Big Bend PM Minimization and Monitoring	196,271	301,141	(104,870)	-34.8%
	f. Big Bend NO_x Emissions Reduction	6	6,006	(6,000)	-99.9%
	g. NPDES Annual Surveillance Fees	34,500	34,500	-	0.0%
	h. Gannon Thermal Discharge Study	-	-	-	0.0%
	i. Polk NO_x Emissions Reduction	-	-	-	0.0%
	j. Bayside SCR Consumables	109,846	93,185	16,661	17.9%
	k. Big Bend Unit 4 SOFA	-	-	-	0.0%
	l. Big Bend Unit 1 Pre-SCR	-	5,400	(5,400)	-100.0%
	m. Big Bend Unit 2 Pre-SCR	775	6,175	(5,400)	-87.4%
	n. Big Bend Unit 3 Pre-SCR	815	6,815	(6,000)	-88.0%
	o. Clean Water Act Section 316(b) Phase II Study	11,446	28,110	(16,664)	-59.3%
	p. Arsenic Groundwater Standard Program	31,285	15,858	15,426	97.3%
	q. Big Bend 1 SCR	16,552	87,529	(70,977)	-81.1%
	r. Big Bend 2 SCR	142,594	252,179	(109,585)	-43.5%
	s. Big Bend 3 SCR	348,572	457,095	(108,523)	-23.7%
	t. Big Bend 4 SCR	503,030	727,138	(224,108)	-30.8%
	u. Mercury Air Toxics Standards	1,933	1,873	60	3.2%
	v. Greenhouse Gas Reduction Program	93,149	93,149	-	0.0%
	w. Big Bend Gypsum Storage Facility	365,664	796,177	(430,513)	-54.1%
	x. Coal Combustion Residuals (CCR) Rule	1,015,110	6,381	1,008,729	15809.2%
	y. Big Bend ELG Compliance	515	515	-	0.0%
	z. CCR Rule - Phase II	11,310,929	14,257,611	(2,946,683)	-20.7%
2.	Total Investment Projects - Recoverable Costs	$14,379,187	$17,596,108	($3,216,922)	-18.3%
3.	Recoverable Costs Allocated to Energy	$14,301,957	$17,517,640	($3,215,684)	-18.4%
4.	Recoverable Costs Allocated to Demand	$77,231	$78,468	($1,238)	-1.6%

Notes:
Column (1) is the End of Period Totals on Form 42-5A.
Column (2) is the approved projected amount in accordance with FPSC Order No. PSC-2020-0433-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

DOCKET NO. 20210007-EI
ECRC 2020 FINAL TRUE-UP
EXHIBIT MAS-1, DOC. NO. 5, PAGE 1 OF 1
REVISED: JUNE 7, 2021

Form 42 - 5A

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

O&M Activities
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total	Method of Classification Demand	Energy
1.	Description of O&M Activities															
	a. Big Bend Unit 3 Flue Gas Desulfurization Integration	$11,352	$9,360	$20,751	$6,779	$30,045	$15,556	($4,272)	$8,969	$6,623	$27,260	$2,258	$37,033	$171,713		$171,713
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	c. SO_2 Emissions Allowances	2	5	4	(39)	0	2	(1)	2	10	1	19	13	19		19
	d. Big Bend Units 1 & 2 FGD	3,833	665	1,428	5,488	2,279	184	8,826	(3,214)	3,900	263	98	714	24,465		24,465
	e. Big Bend PM Minimization and Monitoring	15,123	2,276	509	24,542	18,776	40,666	3,380	16,064	56,611	10,675	3,435	4,215	196,271		196,271
	f. Big Bend NO_x Emissions Reduction	6	0	0	0	0	0	0	0	0	0	0	0	6		6
	g. NPDES Annual Surveillance Fees	46,000	(11,500)	0	0	0	0	0	0	0	0	0	0	34,500	$34,500	
	h. Gannon Thermal Discharge Study	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	i. Polk NO_x Emissions Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	j. Bayside SCR and Ammonia	8,637	11,613	8,680	0	0	3,255	7,644	37,163	10,750	10,854	3,255	7,996	109,846		109,846
	k. Big Bend Unit 4 SOFA	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	l. Big Bend Unit 1 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	m. Big Bend Unit 2 Pre-SCR	0	0	0	0	0	775	0	0	0	0	0	0	775		775
	n. Big Bend Unit 3 Pre-SCR	0	815	0	0	0	0	0	0	0	0	0	0	815		815
	o. Clean Water Act Section 316(b) Phase II Study	0	(498)	0	0	2,219	3,389	0	0	392	1,476	305	4,164	11,446	11,446	
	p. Arsenic Groundwater Standard Program	0	2,014	2,297	453	17,197	(12,102)	21,151	0	275	0	0	0	31,285	31,285	
	q. Big Bend 1 SCR	1,917	6,955	162	5,389	2,130	0	0	0	0	0	0	0	16,552		16,552
	r. Big Bend 2 SCR	26,759	646	5,406	176	9,673	2,373	(5)	3,233	20,198	39,928	3,250	30,958	142,594		142,594
	s. Big Bend 3 SCR	44,130	45,008	32,897	16,070	18,659	8,296	34,530	28,569	47,500	48,051	10,489	14,374	348,572		348,572
	t. Big Bend 4 SCR	47,684	102,104	16,560	9,786	10,017	21,672	37,365	51,085	55,181	57,340	70,726	23,509	503,030		503,030
	u. Mercury Air Toxics Standards	0	0	0	1,621	252	0	0	0	60	0	0	0	1,933		1,933
	v. Greenhouse Gas Reduction Program	0	0	0	93,149	0	0	0	0	0	0	0	0	93,149		93,149
	w. Big Bend Gypsum Storage Facility (East 40)	186,918	61,140	40,791	9,740	4,698	19,357	(5,099)	9,683	10,613	8,458	17,105	2,259	365,664		365,664
	x. Coal Combustion Residuals (CCR) Rule - Phase I	2,988	3,393	0	0	0	0	0	23,800	141,921	438,367	237,954	166,687	1,015,110		1,015,110
	y. Big Bend ELG Compliance	0	0	515	0	0	0	0	0	0	0	0	0	515		515
	z. Coal Combustion Residuals (CCR) Rule - Phase II	343,254	98,022	1,334,995	2,465,726	896,487	2,073,546	1,812,126	5,604	1,044,939	546,693	(14,040)	703,578	11,310,929		11,310,929
2.	Total of O&M Activities	738,601	332,017	1,464,995	2,638,880	1,012,431	2,176,969	1,915,644	180,958	1,398,973	1,189,367	334,852	995,500	14,379,187	$77,231	$14,301,957
3.	Recoverable Costs Allocated to Energy	692,601	342,001	1,462,698	2,638,427	993,016	2,185,682	1,894,493	180,958	1,398,307	1,187,891	334,547	991,336	14,301,956		
4.	Recoverable Costs Allocated to Demand	46,000	(9,984)	2,297	453	19,415	(8,713)	21,151	0	666	1,476	305	4,164	77,231		
5.	Retail Energy Jurisdictional Factor	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
6.	Retail Demand Jurisdictional Factor	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
7.	Jurisdictional Energy Recoverable Costs (A)	692,601	342,001	1,462,698	2,638,427	993,016	2,185,682	1,894,493	180,958	1,398,307	1,187,891	334,547	991,336	14,301,956		
8.	Jurisdictional Demand Recoverable Costs (B)	46,000	(9,984)	2,297	453	19,415	(8,713)	21,151	0	666	1,476	305	4,164	77,231		
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$738,601	$332,017	$1,464,995	$2,638,880	$1,012,431	$2,176,969	$1,915,644	$180,958	1,398,973	1,189,367	$334,852	$995,500	$14,379,187		

whlsl

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6

Form 42 - 6A

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Variance Report of Capital Investment Projects - Recoverable Costs
(In Dollars)

Line			(1) Actual	(2) Actual/Estimated Projection	(3) Variance Amount	(4) Percent
1.		Description of Investment Projects				
	a.	Big Bend Unit 3 Flue Gas Desulfurization Integration	$924,091	$924,091	$0	0.0%
	b.	Big Bend Units 1 & 2 Flue Gas Conditioning	221,125	221,125	0	0.0%
	c.	Big Bend Unit 4 Continuous Emissions Monitors	47,462	47,462	0	0.0%
	d.	Big Bend Fuel Oil Tank # 1 Upgrade	68,615	68,615	0	0.0%
	e.	Big Bend Fuel Oil Tank # 2 Upgrade	112,855	112,855	0	0.0%
	f.	Big Bend Unit 1 Classifier Replacement	73,018	73,018	0	0.0%
	g.	Big Bend Unit 2 Classifier Replacement	53,081	53,081	0	0.0%
	h.	Big Bend Section 114 Mercury Testing Platform	8,161	8,161	0	0.0%
	i.	Big Bend Units 1 & 2 FGD	5,648,115	5,648,115	0	0.0%
	j.	Big Bend FGD Optimization and Utilization	1,536,807	1,536,807	0	0.0%
	k.	Big Bend NO_x Emissions Reduction	490,945	490,945	0	0.0%
	l.	Big Bend PM Minimization and Monitoring	1,726,237	1,726,237	0	0.0%
	m.	Polk NO_x Emissions Reduction	106,750	106,750	0	0.0%
	n.	Big Bend Unit 4 SOFA	189,720	189,720	0	0.0%
	o.	Big Bend Unit 1 Pre-SCR	129,410	129,410	0	0.0%
	p.	Big Bend Unit 2 Pre-SCR	123,724	123,724	0	0.0%
	q.	Big Bend Unit 3 Pre-SCR	222,214	222,214	0	0.0%
	r.	Big Bend Unit 1 SCR	7,398,711	7,398,711	0	0.0%
	s.	Big Bend Unit 2 SCR	8,118,899	8,118,899	0	0.0%
	t.	Big Bend Unit 3 SCR	6,610,540	6,610,540	0	0.0%
	u.	Big Bend Unit 4 SCR	5,300,112	5,300,112	0	0.0%
	v.	Big Bend FGD System Reliability	2,039,210	2,039,210	0	0.0%
	w.	Mercury Air Toxics Standards	795,655	795,655	0	0.0%
	x.	$S0_2$ Emissions Allowances	(2,658)	(2,658)	0	0.0%
	y.	Big Bend Gypsum Storage Facility	2,017,798	2,017,798	0	0.0%
	z.	Big Bend Coal Combustion Residual Rule (CCR Rule)	136,724	162,574	(25,850)	-15.9%
	aa.	Coal Combustion Residuals (CCR-Phase II)	69,050	108,456	(39,406)	-36.3%
	ab.	Big Bend ELG Compliance	26,470	79,304	(52,834)	-66.6%
	ac.	Big Bend Unit 1 Sec. 316(b) Impingement Mortality	30,848	31,605	(757)	-2.4%
2.		Total Investment Projects - Recoverable Costs	$44,223,689	$44,342,536	($118,847)	-0.3%
3.		Recoverable Costs Allocated to Energy	$43,779,127	$43,779,127	$0	0.0%
4.		Recoverable Costs Allocated to Demand	$444,562	$563,409	($118,847)	-21.1%

Notes:
Column (1) is the End of Period Totals on Form 42-7A.
Column (2) is the approved projected amount in accordance with FPSC Order No. PSC-2020-0433-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

DOCKET NO. 20210007-EI
ECRC 2020 FINAL TRUE-UP
EXHIBIT MAS-1, DOC. NO. 7, PAGE 1 OF 1
REVISED: JUNE 7, 2021

Form 42-7A

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line	Description (A)	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1. a.	Big Bend Unit 3 Flue Gas Desulfurization Integration	$77,713	$77,527	$77,343	$77,158	$76,972	$76,787	$77,234	$77,046	$76,859	$76,671	$76,484	$76,297	$924,091		$924,091
b.	Big Bend Units 1 and 2 Flue Gas Conditioning	18,984	18,880	18,776	18,673	18,570	18,465	18,392	18,287	18,182	18,077	17,972	17,867	221,125		221,125
c.	Big Bend Unit 4 Continuous Emissions Monitors	4,026	4,012	3,996	3,982	3,967	3,952	3,959	3,943	3,929	3,913	3,899	3,884	47,462		47,462
d.	Big Bend Fuel Oil Tank # 1 Upgrade	5,895	5,863	5,829	5,797	5,764	5,731	5,706	5,672	5,640	5,606	5,572	5,540	68,615	$68,615	
e.	Big Bend Fuel Oil Tank # 2 Upgrade	9,697	9,642	9,588	9,534	9,481	9,427	9,384	9,330	9,275	9,221	9,166	9,110	112,855	112,855	
f.	Big Bend Unit 1 Classifier Replacement	6,229	6,201	6,173	6,144	6,117	6,089	6,082	6,054	6,025	5,997	5,968	5,939	73,018		73,018
g.	Big Bend Unit 2 Classifier Replacement	4,522	4,503	4,482	4,463	4,444	4,424	4,423	4,403	4,384	4,364	4,345	4,324	53,081		53,081
h.	Big Bend Section 114 Mercury Testing Platform	688	686	684	682	681	678	682	680	678	676	674	672	8,161		8,161
i.	Big Bend Units 1 & 2 FGD	478,583	476,901	475,221	473,540	471,860	470,179	471,229	469,526	467,824	466,120	464,417	462,715	5,648,115		5,648,115
j.	Big Bend FGD Optimization and Utilization	129,227	128,921	128,615	128,309	128,004	127,698	128,447	128,137	127,827	127,518	127,207	126,897	1,536,807		1,536,807
k.	Big Bend NO_x Emissions Reduction	41,071	41,006	40,940	40,875	40,810	40,744	41,082	41,016	40,950	40,883	40,817	40,751	490,945		490,945
l.	Big Bend PM Minimization and Monitoring	145,465	145,074	144,683	144,292	143,902	143,511	144,208	143,812	143,416	143,020	142,625	142,229	1,726,237		1,726,237
m.	Polk NO_x Emissions Reduction	9,023	8,995	8,967	8,938	8,910	8,881	8,911	8,882	8,854	8,825	8,797	8,767	106,750		106,750
n.	Big Bend Unit 4 SOFA	15,974	15,934	15,893	15,852	15,810	15,769	15,852	15,811	15,769	15,727	15,685	15,644	189,720		189,720
o.	Big Bend Unit 1 Pre-SCR	10,944	10,909	10,874	10,838	10,803	10,768	10,802	10,766	10,730	10,694	10,659	10,623	129,410		129,410
p.	Big Bend Unit 2 Pre-SCR	10,447	10,416	10,385	10,353	10,322	10,291	10,331	10,299	10,267	10,236	10,204	10,173	123,724		123,724
q.	Big Bend Unit 3 Pre-SCR	18,730	18,679	18,628	18,577	18,526	18,475	18,563	18,511	18,459	18,407	18,355	18,304	222,214		222,214
r.	Big Bend Unit 1 SCR	625,491	623,508	621,523	619,540	617,555	615,572	617,612	615,602	613,592	611,582	609,572	607,562	7,398,711		7,398,711
s.	Big Bend Unit 2 SCR	685,248	683,243	681,238	679,234	677,230	675,225	677,991	675,960	673,929	671,898	669,867	667,836	8,118,899		8,118,899
t.	Big Bend Unit 3 SCR	557,845	556,227	554,610	552,992	551,374	549,757	552,053	550,414	548,776	547,136	545,498	543,858	6,610,540		6,610,540
u.	Big Bend Unit 4 SCR	446,857	445,621	444,387	443,151	441,917	440,681	442,712	441,460	440,209	438,957	437,706	436,454	5,300,112		5,300,112
v.	Big Bend FGD System Reliability	170,984	170,653	170,322	169,991	169,660	169,329	170,551	170,215	169,880	169,544	169,208	168,873	2,039,210		2,039,210
w.	Mercury Air Toxics Standards	66,806	66,662	66,519	66,376	66,233	66,090	66,524	66,379	66,234	66,089	65,944	65,799	795,655		795,655
x.	SO_2 Emissions Allowances (B)	(220)	(220)	(220)	(220)	(220)	(220)	(223)	(223)	(223)	(223)	(223)	(223)	(2,658)		(2,658)
y.	Big Bend Gypsum Storage Facility	169,224	168,891	168,558	168,225	167,892	167,559	168,751	168,414	168,077	167,740	167,402	167,065	2,017,798		2,017,798
z.	Big Bend Coal Combustion Residual Rule (CCR Rule)	9,841	9,886	9,913	9,937	9,995	10,099	10,429	11,022	11,956	13,154	14,056	16,436	136,724	136,724	
aa.	Coal Combustion Residuals (CCR-Phase II)	4,432	4,563	4,731	4,924	5,163	5,505	5,945	6,225	6,441	6,648	7,047	7,426	69,050	69,050	
ab.	Big Bend ELG Compliance	907	931	1,016	1,153	1,292	1,446	1,616	1,731	1,835	1,964	2,698	9,881	26,470	26,470	
ac.	Big Bend Unit 1 Impingement Mortality - 316(b)	395	431	718	1,051	1,196	1,530	1,941	2,168	3,744	5,436	5,789	6,449	30,848	30,848	
2.	Total Investment Projects - Recoverable Costs	3,725,028	3,714,545	3,704,392	3,694,361	3,684,230	3,674,442	3,691,189	3,681,542	3,673,518	3,665,880	3,657,410	3,657,152	44,223,689	$444,562	$43,779,127
3.	Recoverable Costs Allocated to Energy	3,693,861	3,683,229	3,672,597	3,661,965	3,651,339	3,640,704	3,656,168	3,645,394	3,634,627	3,623,851	3,613,082	3,602,310	43,779,127		43,779,127
4.	Recoverable Costs Allocated to Demand	31,167	31,316	31,795	32,396	32,891	33,738	35,021	36,148	38,891	42,029	44,328	54,842	444,562	444,562	
5.	Retail Energy Jurisdictional Factor	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
6.	Retail Demand Jurisdictional Factor	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
7.	Jurisdictional Energy Recoverable Costs (C)	3,693,861	3,683,229	3,672,597	3,661,965	3,651,339	3,640,704	3,656,168	3,645,394	3,634,627	3,623,851	3,613,082	3,602,310	43,779,127		
8.	Jurisdictional Demand Recoverable Costs (D)	31,167	31,316	31,795	32,396	32,891	33,738	35,021	36,148	38,891	42,029	44,328	54,842	444,562		
9.	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$3,725,028	$3,714,545	$3,704,392	$3,694,361	$3,684,230	$3,674,442	$3,691,189	$3,681,542	$3,673,518	$3,665,880	$3,657,410	$3,657,152	$44,223,689		

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-8A, Line 9
(B) Project's Total Return Component on Form 42-8A, Line 6
(C) Line 3 x Line 5
(D) Line 4 x Line 6

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Flue Gas Desulfurization Integration
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	
3.	Less: Accumulated Depreciation	(6,132,393)	(6,161,231)	(6,190,069)	(6,218,907)	(6,247,745)	(6,276,583)	(6,305,421)	(6,334,259)	(6,363,097)	(6,391,935)	(6,420,773)	(6,449,611)	(6,478,449)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$7,630,870	7,602,032	7,573,194	7,544,356	7,515,518	7,486,680	7,457,842	7,429,004	7,400,166	7,371,328	7,342,490	7,313,652	7,284,814	
6.	Average Net Investment		7,616,451	7,587,613	7,558,775	7,529,937	7,501,099	7,472,261	7,443,423	7,414,585	7,385,747	7,356,909	7,328,071	7,299,233	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$37,851	$37,707	$37,564	$37,421	$37,277	$37,134	$37,277	$37,132	$36,988	$36,843	$36,699	$36,555	$446,448
	b. Debt Component Grossed Up For Taxes (C)		11,024	10,982	10,941	10,899	10,857	10,815	11,119	11,076	11,033	10,990	10,947	10,904	131,587
8.	Investment Expenses														
	a. Depreciation (D)		28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	346,056
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		77,713	77,527	77,343	77,158	76,972	76,787	77,234	77,046	76,859	76,671	76,484	76,297	924,091
	a. Recoverable Costs Allocated to Energy		77,713	77,527	77,343	77,158	76,972	76,787	77,234	77,046	76,859	76,671	76,484	76,297	924,091
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		77,713	77,527	77,343	77,158	76,972	76,787	77,234	77,046	76,859	76,671	76,484	76,297	924,091
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$77,713	$77,527	$77,343	$77,158	$76,972	$76,787	$77,234	$77,046	$76,859	$76,671	$76,484	$76,297	$924,091

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.45 ($13,435,775), 315.45 ($327,307), and 312.40 ($182).
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 2.5%, 3.1%, and 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 Flue Gas Conditioning
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	
3.	Less: Accumulated Depreciation	(4,566,662)	(4,582,803)	(4,598,944)	(4,615,085)	(4,631,226)	(4,647,367)	(4,663,508)	(4,679,649)	(4,695,790)	(4,711,931)	(4,728,072)	(4,744,213)	(4,760,354)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$451,072	434,931	418,790	402,649	386,508	370,367	354,226	338,085	321,944	305,803	289,662	273,521	257,380	
6.	Average Net Investment		443,002	426,861	410,720	394,579	378,438	362,297	346,156	330,015	313,874	297,733	281,592	265,451	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$2,202	$2,121	$2,041	$1,961	$1,881	$1,800	$1,734	$1,653	$1,572	$1,491	$1,410	$1,329	$21,195
	b. Debt Component Grossed Up For Taxes (C)		641	618	594	571	548	524	517	493	469	445	421	397	6,238
8.	Investment Expenses														
	a. Depreciation (D)		16,141	16,141	16,141	16,141	16,141	16,141	16,141	16,141	16,141	16,141	16,141	16,141	193,692
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		18,984	18,880	18,776	18,673	18,570	18,465	18,392	18,287	18,182	18,077	17,972	17,867	221,125
	a. Recoverable Costs Allocated to Energy		18,984	18,880	18,776	18,673	18,570	18,465	18,392	18,287	18,182	18,077	17,972	17,867	221,125
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		18,984	18,880	18,776	18,673	18,570	18,465	18,392	18,287	18,182	18,077	17,972	17,867	221,125
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$18,984	$18,880	$18,776	$18,673	$18,570	$18,465	$18,392	$18,287	$18,182	$18,077	$17,972	$17,867	$221,125

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($2,676,217) and 312.42 ($2,341,517).
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 4.0% and 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 Continuous Emissions Monitors
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	
3.	Less: Accumulated Depreciation	(597,605)	(599,915)	(602,225)	(604,535)	(606,845)	(609,155)	(611,465)	(613,775)	(616,085)	(618,395)	(620,705)	(623,015)	(625,325)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$268,606	266,296	263,986	261,676	259,366	257,056	254,746	252,436	250,126	247,816	245,506	243,196	240,886	
6.	Average Net Investment		267,451	265,141	262,831	260,521	258,211	255,901	253,591	251,281	248,971	246,661	244,351	242,041	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,329	$1,318	$1,306	$1,295	$1,283	$1,272	$1,270	$1,258	$1,247	$1,235	$1,224	$1,212	$15,249
	b. Debt Component Grossed Up For Taxes (C)		387	384	380	377	374	370	379	375	372	368	365	362	4,493
8.	Investment Expenses														
	a. Depreciation (D)		2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	27,720
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		4,026	4,012	3,996	3,982	3,967	3,952	3,959	3,943	3,929	3,913	3,899	3,884	47,462
	a. Recoverable Costs Allocated to Energy		4,026	4,012	3,996	3,982	3,967	3,952	3,959	3,943	3,929	3,913	3,899	3,884	47,462
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		4,026	4,012	3,996	3,982	3,967	3,952	3,959	3,943	3,929	3,913	3,899	3,884	47,462
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$4,026	$4,012	$3,996	$3,982	$3,967	$3,952	$3,959	$3,943	$3,929	$3,913	$3,899	$3,884	$47,462

Notes:
(A) Applicable depreciable base for Big Bend; account 315.44
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 3.2%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 1 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	
3.	Less: Accumulated Depreciation	(374,626)	(379,749)	(384,872)	(389,995)	(395,118)	(400,241)	(405,364)	(410,487)	(415,610)	(420,733)	(425,856)	(430,979)	(436,102)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$122,952	117,829	112,706	107,583	102,460	97,337	92,214	87,091	81,968	76,845	71,722	66,599	61,476	
6.	Average Net Investment		120,391	115,268	110,145	105,022	99,899	94,776	89,653	84,530	79,407	74,284	69,161	64,038	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$598	$573	$547	$522	$496	$471	$449	$423	$398	$372	$346	$321	$5,516
	b. Debt Component Grossed Up For Taxes (C)		174	167	159	152	145	137	134	126	119	111	103	96	1,623
8.	Investment Expenses														
	a. Depreciation (D)		5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	61,476
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		5,895	5,863	5,829	5,797	5,764	5,731	5,706	5,672	5,640	5,606	5,572	5,540	68,615
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		5,895	5,863	5,829	5,797	5,764	5,731	5,706	5,672	5,640	5,606	5,572	5,540	68,615
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		5,895	5,863	5,829	5,797	5,764	5,731	5,706	5,672	5,640	5,606	5,572	5,540	68,615
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$5,895	$5,863	$5,829	$5,797	$5,764	$5,731	$5,706	$5,672	$5,640	$5,606	$5,572	$5,540	$68,615

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 12.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 2 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	
3.	Less: Accumulated Depreciation	(616,174)	(624,600)	(633,026)	(641,452)	(649,878)	(658,304)	(666,730)	(675,156)	(683,582)	(692,008)	(700,434)	(708,860)	(717,286)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$202,227	193,801	185,375	176,949	168,523	160,097	151,671	143,245	134,819	126,393	117,967	109,541	101,115	
6.	Average Net Investment		198,014	189,588	181,162	172,736	164,310	155,884	147,458	139,032	130,606	122,180	113,754	105,328	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$984	$942	$900	$858	$817	$775	$738	$696	$654	$612	$570	$527	$9,073
	b. Debt Component Grossed Up For Taxes (C)		287	274	262	250	238	226	220	208	195	183	170	157	2,670
8.	Investment Expenses														
	a. Depreciation (D)		8,426	8,426	8,426	8,426	8,426	8,426	8,426	8,426	8,426	8,426	8,426	8,426	101,112
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		9,697	9,642	9,588	9,534	9,481	9,427	9,384	9,330	9,275	9,221	9,166	9,110	112,855
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		9,697	9,642	9,588	9,534	9,481	9,427	9,384	9,330	9,275	9,221	9,166	9,110	112,855
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		9,697	9,642	9,588	9,534	9,481	9,427	9,384	9,330	9,275	9,221	9,166	9,110	112,855
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$9,697	$9,642	$9,588	$9,534	$9,481	$9,427	$9,384	$9,330	$9,275	$9,221	$9,166	$9,110	$112,855

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 12.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	
3.	Less: Accumulated Depreciation	(1,027,160)	(1,031,548)	(1,035,936)	(1,040,324)	(1,044,712)	(1,049,100)	(1,053,488)	(1,057,876)	(1,062,264)	(1,066,652)	(1,071,040)	(1,075,428)	(1,079,816)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$289,097	284,709	280,321	275,933	271,545	267,157	262,769	258,381	253,993	249,605	245,217	240,829	236,441	
6.	Average Net Investment		286,903	282,515	278,127	273,739	269,351	264,963	260,575	256,187	251,799	247,411	243,023	238,635	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,426	$1,404	$1,382	$1,360	$1,339	$1,317	$1,305	$1,283	$1,261	$1,239	$1,217	$1,195	$15,728
	b. Debt Component Grossed Up For Taxes (C)		415	409	403	396	390	384	389	383	376	370	363	356	4,634
8.	Investment Expenses														
	a. Depreciation (D)		4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	52,656
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		6,229	6,201	6,173	6,144	6,117	6,089	6,082	6,054	6,025	5,997	5,968	5,939	73,018
	a. Recoverable Costs Allocated to Energy		6,229	6,201	6,173	6,144	6,117	6,089	6,082	6,054	6,025	5,997	5,968	5,939	73,018
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		6,229	6,201	6,173	6,144	6,117	6,089	6,082	6,054	6,025	5,997	5,968	5,939	73,018
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$6,229	$6,201	$6,173	$6,144	$6,117	$6,089	$6,082	$6,054	$6,025	$5,997	$5,968	$5,939	$73,018

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 4.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	
3.	Less: Accumulated Depreciation	(751,734)	(754,770)	(757,806)	(760,842)	(763,878)	(766,914)	(769,950)	(772,986)	(776,022)	(779,058)	(782,094)	(785,130)	(788,166)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$233,060	230,024	226,988	223,952	220,916	217,880	214,844	211,808	208,772	205,736	202,700	199,664	196,628	
6.	Average Net Investment		231,542	228,506	225,470	222,434	219,398	216,362	213,326	210,290	207,254	204,218	201,182	198,146	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,151	$1,136	$1,120	$1,105	$1,090	$1,075	$1,068	$1,053	$1,038	$1,023	$1,008	$992	$12,859
	b. Debt Component Grossed Up For Taxes (C)		335	331	326	322	318	313	319	314	310	305	301	296	3,790
8.	Investment Expenses														
	a. Depreciation (D)		3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	36,432
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		4,522	4,503	4,482	4,463	4,444	4,424	4,423	4,403	4,384	4,364	4,345	4,324	53,081
	a. Recoverable Costs Allocated to Energy		4,522	4,503	4,482	4,463	4,444	4,424	4,423	4,403	4,384	4,364	4,345	4,324	53,081
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		4,522	4,503	4,482	4,463	4,444	4,424	4,423	4,403	4,384	4,364	4,345	4,324	53,081
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
15	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$4,522	$4,503	$4,482	$4,463	$4,444	$4,424	$4,423	$4,403	$4,384	$4,364	$4,345	$4,324	$53,081

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Section 114 Mercury Testing Platform
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	
3.	Less: Accumulated Depreciation	(58,915)	(59,207)	(59,499)	(59,791)	(60,083)	(60,375)	(60,667)	(60,959)	(61,251)	(61,543)	(61,835)	(62,127)	(62,419)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$61,822	61,530	61,238	60,946	60,654	60,362	60,070	59,778	59,486	59,194	58,902	58,610	58,318	
6.	Average Net Investment		61,676	61,384	61,092	60,800	60,508	60,216	59,924	59,632	59,340	59,048	58,756	58,464	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$307	$305	$304	$302	$301	$299	$300	$299	$297	$296	$294	$293	$3,597
	b. Debt Component Grossed Up For Taxes (C)		89	89	88	88	88	87	90	89	89	88	88	87	1,060
8.	Investment Expenses														
	a. Depreciation (D)		292	292	292	292	292	292	292	292	292	292	292	292	3,504
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		688	686	684	682	681	678	682	680	678	676	674	672	8,161
	a. Recoverable Costs Allocated to Energy		688	686	684	682	681	678	682	680	678	676	674	672	8,161
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		688	686	684	682	681	678	682	680	678	676	674	672	8,161
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$688	$686	$684	$682	$681	$678	$682	$680	$678	$676	$674	$672	$8,161

Notes:
(A) Applicable depreciable base for Big Bend; account 311.40
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 2.9%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 FGD
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	
3.	Less: Accumulated Depreciation	(61,360,265)	(61,622,184)	(61,884,103)	(62,146,022)	(62,407,941)	(62,669,860)	(62,931,779)	(63,193,698)	(63,455,617)	(63,717,536)	(63,979,455)	(64,241,374)	(64,503,293)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$33,894,977	33,633,058	33,371,139	33,109,220	32,847,301	32,585,382	32,323,463	32,061,544	31,799,625	31,537,706	31,275,787	31,013,868	30,751,949	
6.	Average Net Investment		33,764,017	33,502,098	33,240,179	32,978,260	32,716,341	32,454,422	32,192,503	31,930,584	31,668,665	31,406,746	31,144,827	30,882,908	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$167,793	$166,491	$165,190	$163,888	$162,587	$161,285	$161,220	$159,908	$158,597	$157,285	$155,973	$154,662	$1,934,879
	b. Debt Component Grossed Up For Taxes (C)		48,871	48,491	48,112	47,733	47,354	46,975	48,090	47,699	47,308	46,916	46,525	46,134	570,208
8.	Investment Expenses														
	a. Depreciation (D)		261,919	261,919	261,919	261,919	261,919	261,919	261,919	261,919	261,919	261,919	261,919	261,919	3,143,028
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		478,583	476,901	475,221	473,540	471,860	470,179	471,229	469,526	467,824	466,120	464,417	462,715	5,648,115
	a. Recoverable Costs Allocated to Energy		478,583	476,901	475,221	473,540	471,860	470,179	471,229	469,526	467,824	466,120	464,417	462,715	5,648,115
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		478,583	476,901	475,221	473,540	471,860	470,179	471,229	469,526	467,824	466,120	464,417	462,715	5,648,115
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$478,583	$476,901	$475,221	$473,540	$471,860	$470,179	$471,229	$469,526	$467,824	$466,120	$464,417	$462,715	$5,648,115

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.46 ($94,929,061), 312.45 ($105,398), and 315.46 ($220,782).
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 3.3%, 2.5%, and 3.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD Optimization and Utilization
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	
3.	Less: Accumulated Depreciation	(9,917,006)	(9,964,653)	(10,012,300)	(10,059,947)	(10,107,594)	(10,155,241)	(10,202,888)	(10,250,535)	(10,298,182)	(10,345,829)	(10,393,476)	(10,441,123)	(10,488,770)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$12,736,923	12,689,276	12,641,629	12,593,982	12,546,335	12,498,688	12,451,041	12,403,394	12,355,747	12,308,100	12,260,453	12,212,806	12,165,159	
6.	Average Net Investment		12,713,100	12,665,453	12,617,806	12,570,159	12,522,512	12,474,865	12,427,218	12,379,571	12,331,924	12,284,277	12,236,630	12,188,983	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$63,179	$62,942	$62,705	$62,468	$62,232	$61,995	$62,236	$61,997	$61,758	$61,520	$61,281	$61,042	$745,355
	b. Debt Component Grossed Up For Taxes (C)		18,401	18,332	18,263	18,194	18,125	18,056	18,564	18,493	18,422	18,351	18,279	18,208	219,688
8.	Investment Expenses														
	a. Depreciation (D)		47,647	47,647	47,647	47,647	47,647	47,647	47,647	47,647	47,647	47,647	47,647	47,647	571,764
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		129,227	128,921	128,615	128,309	128,004	127,698	128,447	128,137	127,827	127,518	127,207	126,897	1,536,807
	a. Recoverable Costs Allocated to Energy		129,227	128,921	128,615	128,309	128,004	127,698	128,447	128,137	127,827	127,518	127,207	126,897	1,536,807
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		129,227	128,921	128,615	128,309	128,004	127,698	128,447	128,137	127,827	127,518	127,207	126,897	1,536,807
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$129,227	$128,921	$128,615	$128,309	$128,004	$127,698	$128,447	$128,137	$127,827	$127,518	$127,207	$126,897	$1,536,807

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.45 ($21,855,886), 311.45 ($40,016), 316.40 ($71,401), 315.45 ($594,901), 312.42 ($1,637), and 312.40 ($90,088).
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 2.5%, 2.0%, 4.2%, 3.1%, 3.7%, and 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	
3.	Less: Accumulated Depreciation	1,627,563	1,617,379	1,607,195	1,597,011	1,586,827	1,576,643	1,566,459	1,556,275	1,546,091	1,535,907	1,525,723	1,515,539	1,505,355	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$4,818,415	4,808,231	4,798,047	4,787,863	4,777,679	4,767,495	4,757,311	4,747,127	4,736,943	4,726,759	4,716,575	4,706,391	4,696,207	
6.	Average Net Investment		4,813,323	4,803,139	4,792,955	4,782,771	4,772,587	4,762,403	4,752,219	4,742,035	4,731,851	4,721,667	4,711,483	4,701,299	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$23,920	$23,870	$23,819	$23,768	$23,718	$23,667	$23,799	$23,748	$23,697	$23,646	$23,595	$23,544	$284,791
	b. Debt Component Grossed Up For Taxes (C)		6,967	6,952	6,937	6,923	6,908	6,893	7,099	7,084	7,069	7,053	7,038	7,023	83,946
8.	Investment Expenses														
	a. Depreciation (D)		10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	122,208
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		41,071	41,006	40,940	40,875	40,810	40,744	41,082	41,016	40,950	40,883	40,817	40,751	490,945
	a. Recoverable Costs Allocated to Energy		41,071	41,006	40,940	40,875	40,810	40,744	41,082	41,016	40,950	40,883	40,817	40,751	490,945
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		41,071	41,006	40,940	40,875	40,810	40,744	41,082	41,016	40,950	40,883	40,817	40,751	490,945
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$41,071	$41,006	$40,940	$40,875	$40,810	$40,744	$41,082	$41,016	$40,950	$40,883	$40,817	$40,751	$490,945

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,675,171), 312.42 ($1,075,718), and 312.43 ($439,963).
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 4.0%, 3.7%, and 3.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: PM Minimization and Monitoring
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	
3.	Less: Accumulated Depreciation	(6,544,786)	(6,605,658)	(6,666,530)	(6,727,402)	(6,788,274)	(6,849,146)	(6,910,018)	(6,970,890)	(7,031,762)	(7,092,634)	(7,153,506)	(7,214,378)	(7,275,250)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$13,212,964	13,152,092	13,091,220	13,030,348	12,969,476	12,908,604	12,847,732	12,786,860	12,725,988	12,665,116	12,604,244	12,543,372	12,482,500	
6.	Average Net Investment		13,182,528	13,121,656	13,060,784	12,999,912	12,939,040	12,878,168	12,817,296	12,756,424	12,695,552	12,634,680	12,573,808	12,512,936	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$65,512	$65,209	$64,907	$64,604	$64,302	$63,999	$64,189	$63,884	$63,579	$63,274	$62,970	$62,665	$769,094
	b. Debt Component Grossed Up For Taxes (C)		19,081	18,993	18,904	18,816	18,728	18,640	19,147	19,056	18,965	18,874	18,783	18,692	226,679
8.	Investment Expenses														
	a. Depreciation (D)		60,872	60,872	60,872	60,872	60,872	60,872	60,872	60,872	60,872	60,872	60,872	60,872	730,464
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		145,465	145,074	144,683	144,292	143,902	143,511	144,208	143,812	143,416	143,020	142,625	142,229	1,726,237
	a. Recoverable Costs Allocated to Energy		145,465	145,074	144,683	144,292	143,902	143,511	144,208	143,812	143,416	143,020	142,625	142,229	1,726,237
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		145,465	145,074	144,683	144,292	143,902	143,511	144,208	143,812	143,416	143,020	142,625	142,229	1,726,237
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$145,465	$145,074	$144,683	$144,292	$143,902	$143,511	$144,208	$143,812	$143,416	$143,020	$142,625	$142,229	$1,726,237

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($5,831,465), 312.42 ($5,153,072), 312.43 ($7,875,560), 315.41 ($17,504), 315.44 ($351,594), and 315.43 ($528,554).
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 4.0%, 3.7%, 3.5%, 3.5%, 3.2%, and 3.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Polk NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	
3.	Less: Accumulated Depreciation	(842,586)	(847,010)	(851,434)	(855,858)	(860,282)	(864,706)	(869,130)	(873,554)	(877,978)	(882,402)	(886,826)	(891,250)	(895,674)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$718,887	714,463	710,039	705,615	701,191	696,767	692,343	687,919	683,495	679,071	674,647	670,223	665,799	
6.	Average Net Investment		716,675	712,251	707,827	703,403	698,979	694,555	690,131	685,707	681,283	676,859	672,435	668,011	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$3,562	$3,540	$3,518	$3,496	$3,474	$3,452	$3,456	$3,434	$3,412	$3,390	$3,368	$3,345	$41,447
	b. Debt Component Grossed Up For Taxes (C)		1,037	1,031	1,025	1,018	1,012	1,005	1,031	1,024	1,018	1,011	1,005	998	12,215
8.	Investment Expenses														
	a. Depreciation (D)		4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	53,088
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		9,023	8,995	8,967	8,938	8,910	8,881	8,911	8,882	8,854	8,825	8,797	8,767	106,750
	a. Recoverable Costs Allocated to Energy		9,023	8,995	8,967	8,938	8,910	8,881	8,911	8,882	8,854	8,825	8,797	8,767	106,750
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		9,023	8,995	8,967	8,938	8,910	8,881	8,911	8,882	8,854	8,825	8,797	8,767	106,750
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$9,023	$8,995	$8,967	$8,938	$8,910	$8,881	$8,911	$8,882	$8,854	$8,825	$8,797	$8,767	$106,750

Notes:
(A) Applicable depreciable base for Polk; account 342.81
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SOFA
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	
3.	Less: Accumulated Depreciation	(1,062,962)	(1,069,359)	(1,075,756)	(1,082,153)	(1,088,550)	(1,094,947)	(1,101,344)	(1,107,741)	(1,114,138)	(1,120,535)	(1,126,932)	(1,133,329)	(1,139,726)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,495,768	1,489,371	1,482,974	1,476,577	1,470,180	1,463,783	1,457,386	1,450,989	1,444,592	1,438,195	1,431,798	1,425,401	1,419,004	
6.	Average Net Investment		1,492,570	1,486,173	1,479,776	1,473,379	1,466,982	1,460,585	1,454,188	1,447,791	1,441,394	1,434,997	1,428,600	1,422,203	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$7,417	$7,386	$7,354	$7,322	$7,290	$7,258	$7,283	$7,251	$7,219	$7,186	$7,154	$7,122	$87,242
	b. Debt Component Grossed Up For Taxes (C)		2,160	2,151	2,142	2,133	2,123	2,114	2,172	2,163	2,153	2,144	2,134	2,125	25,714
8.	Investment Expenses														
	a. Depreciation (D)		6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	76,764
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		15,974	15,934	15,893	15,852	15,810	15,769	15,852	15,811	15,769	15,727	15,685	15,644	189,720
	a. Recoverable Costs Allocated to Energy		15,974	15,934	15,893	15,852	15,810	15,769	15,852	15,811	15,769	15,727	15,685	15,644	189,720
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		15,974	15,934	15,893	15,852	15,810	15,769	15,852	15,811	15,769	15,727	15,685	15,644	189,720
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$15,974	$15,934	$15,893	$15,852	$15,810	$15,769	$15,852	$15,811	$15,769	$15,727	$15,685	$15,644	$189,720

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	
3.	Less: Accumulated Depreciation	(797,557)	(803,054)	(808,551)	(814,048)	(819,545)	(825,042)	(830,539)	(836,036)	(841,533)	(847,030)	(852,527)	(858,024)	(863,521)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$851,564	846,067	840,570	835,073	829,576	824,079	818,582	813,085	807,588	802,091	796,594	791,097	785,600	
6.	Average Net Investment		848,816	843,319	837,822	832,325	826,828	821,331	815,834	810,337	804,840	799,343	793,846	788,349	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$4,218	$4,191	$4,164	$4,136	$4,109	$4,082	$4,086	$4,058	$4,031	$4,003	$3,976	$3,948	$49,002
	b. Debt Component Grossed Up For Taxes (C)		1,229	1,221	1,213	1,205	1,197	1,189	1,219	1,211	1,202	1,194	1,186	1,178	14,444
8.	Investment Expenses														
	a. Depreciation (D)		5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	65,964
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		10,944	10,909	10,874	10,838	10,803	10,768	10,802	10,766	10,730	10,694	10,659	10,623	129,410
	a. Recoverable Costs Allocated to Energy		10,944	10,909	10,874	10,838	10,803	10,768	10,802	10,766	10,730	10,694	10,659	10,623	129,410
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		10,944	10,909	10,874	10,838	10,803	10,768	10,802	10,766	10,730	10,694	10,659	10,623	129,410
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$10,944	$10,909	$10,874	$10,838	$10,803	$10,768	$10,802	$10,766	$10,730	$10,694	$10,659	$10,623	$129,410

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 4.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	
3.	Less: Accumulated Depreciation	(711,368)	(716,245)	(721,122)	(725,999)	(730,876)	(735,753)	(740,630)	(745,507)	(750,384)	(755,261)	(760,138)	(765,015)	(769,892)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$870,519	865,642	860,765	855,888	851,011	846,134	841,257	836,380	831,503	826,626	821,749	816,872	811,995	
6.	Average Net Investment		868,081	863,204	858,327	853,450	848,573	843,696	838,819	833,942	829,065	824,188	819,311	814,434	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$4,314	$4,290	$4,266	$4,241	$4,217	$4,193	$4,201	$4,176	$4,152	$4,128	$4,103	$4,079	$50,360
	b. Debt Component Grossed Up For Taxes (C)		1,256	1,249	1,242	1,235	1,228	1,221	1,253	1,246	1,238	1,231	1,224	1,217	14,840
8.	Investment Expenses														
	a. Depreciation (D)		4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	58,524
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		10,447	10,416	10,385	10,353	10,322	10,291	10,331	10,299	10,267	10,236	10,204	10,173	123,724
	a. Recoverable Costs Allocated to Energy		10,447	10,416	10,385	10,353	10,322	10,291	10,331	10,299	10,267	10,236	10,204	10,173	123,724
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		10,447	10,416	10,385	10,353	10,322	10,291	10,331	10,299	10,267	10,236	10,204	10,173	123,724
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$10,447	$10,416	$10,385	$10,353	$10,322	$10,291	$10,331	$10,299	$10,267	$10,236	$10,204	$10,173	$123,724

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	
3.	Less: Accumulated Depreciation	(1,023,074)	(1,031,027)	(1,038,980)	(1,046,933)	(1,054,886)	(1,062,839)	(1,070,792)	(1,078,745)	(1,086,698)	(1,094,651)	(1,102,604)	(1,110,557)	(1,118,510)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,683,433	1,675,480	1,667,527	1,659,574	1,651,621	1,643,668	1,635,715	1,627,762	1,619,809	1,611,856	1,603,903	1,595,950	1,587,997	
6.	Average Net Investment		1,679,457	1,671,504	1,663,551	1,655,598	1,647,645	1,639,692	1,631,739	1,623,786	1,615,833	1,607,880	1,599,927	1,591,974	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$8,346	$8,307	$8,267	$8,228	$8,188	$8,149	$8,172	$8,132	$8,092	$8,052	$8,012	$7,973	$97,918
	b. Debt Component Grossed Up For Taxes (C)		2,431	2,419	2,408	2,396	2,385	2,373	2,438	2,426	2,414	2,402	2,390	2,378	28,860
8.	Investment Expenses														
	a. Depreciation (D)		7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	95,436
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		18,730	18,679	18,628	18,577	18,526	18,475	18,563	18,511	18,459	18,407	18,355	18,304	222,214
	a. Recoverable Costs Allocated to Energy		18,730	18,679	18,628	18,577	18,526	18,475	18,563	18,511	18,459	18,407	18,355	18,304	222,214
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		18,730	18,679	18,628	18,577	18,526	18,475	18,563	18,511	18,459	18,407	18,355	18,304	222,214
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$18,730	$18,679	$18,628	$18,577	$18,526	$18,475	$18,563	$18,511	$18,459	$18,407	$18,355	$18,304	$222,214

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.43 ($1,995,677) and 315.43 ($710,830).
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 3.5% and 3.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DOCKET NO. 20210007-EI
ECRC 2020 FINAL TRUE-UP
EXHIBIT MAS-1, DOC. NO. 8, PAGE 18 OF 29
REVISED: JUNE 7, 2021

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	
3.	Less: Accumulated Depreciation	(36,269,622)	(36,578,788)	(36,887,954)	(37,197,120)	(37,506,286)	(37,815,452)	(38,124,618)	(38,433,784)	(38,742,950)	(39,052,116)	(39,361,282)	(39,670,448)	(39,979,614)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$49,449,480	49,140,314	48,831,148	48,521,982	48,212,816	47,903,650	47,594,484	47,285,318	46,976,152	46,666,986	46,357,820	46,048,654	45,739,488	
6.	Average Net Investment		49,294,897	48,985,731	48,676,565	48,367,399	48,058,233	47,749,067	47,439,901	47,130,735	46,821,569	46,512,403	46,203,237	45,894,071	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$244,975	$243,439	$241,902	$240,366	$238,829	$237,293	$237,579	$236,031	$234,482	$232,934	$231,386	$229,838	$2,849,054
	b. Debt Component Grossed Up For Taxes (C)		71,350	70,903	70,455	70,008	69,560	69,113	70,867	70,405	69,944	69,482	69,020	68,558	839,665
8.	Investment Expenses														
	a. Depreciation (D)		309,166	309,166	309,166	309,166	309,166	309,166	309,166	309,166	309,166	309,166	309,166	309,166	3,709,992
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		625,491	623,508	621,523	619,540	617,555	615,572	617,612	615,602	613,592	611,582	609,572	607,562	7,398,711
	a. Recoverable Costs Allocated to Energy		625,491	623,508	621,523	619,540	617,555	615,572	617,612	615,602	613,592	611,582	609,572	607,562	7,398,711
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		625,491	623,508	621,523	619,540	617,555	615,572	617,612	615,602	613,592	611,582	609,572	607,562	7,398,711
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$625,491	$623,508	$621,523	$619,540	$617,555	$615,572	$617,612	$615,602	$613,592	$611,582	$609,572	$607,562	$7,398,711

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.51 ($22,278,982), 312.51 ($48,529,672), 315.51 ($14,063,245), and 316.51 ($847,203).
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 4.1%, 4.3%, 4.8%, and 4.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	
3.	Less: Accumulated Depreciation	(38,275,236)	(38,587,613)	(38,899,990)	(39,212,367)	(39,524,744)	(39,837,121)	(40,149,498)	(40,461,875)	(40,774,252)	(41,086,629)	(41,399,006)	(41,711,383)	(42,023,760)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$58,262,897	57,950,520	57,638,143	57,325,766	57,013,389	56,701,012	56,388,635	56,076,258	55,763,881	55,451,504	55,139,127	54,826,750	54,514,373	
6.	Average Net Investment		58,106,708	57,794,331	57,481,954	57,169,577	56,857,200	56,544,823	56,232,446	55,920,069	55,607,692	55,295,315	54,982,938	54,670,561	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$288,766	$287,214	$285,661	$284,109	$282,557	$281,004	$281,612	$280,048	$278,483	$276,919	$275,355	$273,790	$3,375,518
	b. Debt Component Grossed Up For Taxes (C)		84,105	83,652	83,200	82,748	82,296	81,844	84,002	83,535	83,069	82,602	82,135	81,669	994,857
8.	Investment Expenses														
	a. Depreciation (D)		312,377	312,377	312,377	312,377	312,377	312,377	312,377	312,377	312,377	312,377	312,377	312,377	3,748,524
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		685,248	683,243	681,238	679,234	677,230	675,225	677,991	675,960	673,929	671,898	669,867	667,836	8,118,899
	a. Recoverable Costs Allocated to Energy		685,248	683,243	681,238	679,234	677,230	675,225	677,991	675,960	673,929	671,898	669,867	667,836	8,118,899
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		685,248	683,243	681,238	679,234	677,230	675,225	677,991	675,960	673,929	671,898	669,867	667,836	8,118,899
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$685,248	$683,243	$681,238	$679,234	$677,230	$675,225	$677,991	$675,960	$673,929	$671,898	$669,867	$667,836	$8,118,899

Notes:
(A) Applicable depreciable base for Big Bend; account 311.52 ($25,208,869), 312.52 ($54,456,221), 315.52 ($15,914,427), and 316.52 ($958,616).
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rates are 3.5%, 4.0%, 4.1% and 3.7%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DOCKET NO. 20210007-EI
ECRC 2020 FINAL TRUE-UP
EXHIBIT MAS-1, DOC. NO. 8, PAGE 20 OF 29
REVISED: JUNE 7, 2021

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	
3.	Less: Accumulated Depreciation	(33,988,473)	(34,240,547)	(34,492,621)	(34,744,695)	(34,996,769)	(35,248,843)	(35,500,917)	(35,752,991)	(36,005,065)	(36,257,139)	(36,509,213)	(36,761,287)	(37,013,361)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$47,776,129	47,524,055	47,271,981	47,019,907	46,767,833	46,515,759	46,263,685	46,011,611	45,759,537	45,507,463	45,255,389	45,003,315	44,751,241	
6.	Average Net Investment		47,650,092	47,398,018	47,145,944	46,893,870	46,641,796	46,389,722	46,137,648	45,885,574	45,633,500	45,381,426	45,129,352	44,877,278	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$236,801	$235,548	$234,296	$233,043	$231,790	$230,538	$231,057	$229,795	$228,533	$227,270	$226,008	$224,745	$2,769,424
	b. Debt Component Grossed Up For Taxes (C)		68,970	68,605	68,240	67,875	67,510	67,145	68,922	68,545	68,169	67,792	67,416	67,039	816,228
8.	Investment Expenses														
	a. Depreciation (D)		252,074	252,074	252,074	252,074	252,074	252,074	252,074	252,074	252,074	252,074	252,074	252,074	3,024,888
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		557,845	556,227	554,610	552,992	551,374	549,757	552,053	550,414	548,776	547,136	545,498	543,858	6,610,540
	a. Recoverable Costs Allocated to Energy		557,845	556,227	554,610	552,992	551,374	549,757	552,053	550,414	548,776	547,136	545,498	543,858	6,610,540
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		557,845	556,227	554,610	552,992	551,374	549,757	552,053	550,414	548,776	547,136	545,498	543,858	6,610,540
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$557,845	$556,227	$554,610	$552,992	$551,374	$549,757	$552,053	$550,414	$548,776	$547,136	$545,498	$543,858	$6,610,540

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.53 ($21,689,422), 312.53 ($45,559,543), 315.53 ($13,690,954), and 316.53 ($824,684).
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 3.1%, 3.9%, 4.0%, and 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	
3.	Less: Accumulated Depreciation	(27,075,687)	(27,268,155)	(27,460,623)	(27,653,091)	(27,845,559)	(28,038,027)	(28,230,495)	(28,422,963)	(28,615,431)	(28,807,899)	(29,000,367)	(29,192,835)	(29,385,303)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$39,739,174	39,546,706	39,354,238	39,161,770	38,969,302	38,776,834	38,584,366	38,391,898	38,199,430	38,006,962	37,814,494	37,622,026	37,429,558	
6.	Average Net Investment		39,642,940	39,450,472	39,258,004	39,065,536	38,873,068	38,680,600	38,488,132	38,295,664	38,103,196	37,910,728	37,718,260	37,525,792	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$197,009	$196,052	$195,096	$194,139	$193,183	$192,226	$192,749	$191,785	$190,821	$189,857	$188,893	$187,929	$2,309,739
	b. Debt Component Grossed Up For Taxes (C)		57,380	57,101	56,823	56,544	56,266	55,987	57,495	57,207	56,920	56,632	56,345	56,057	680,757
8.	Investment Expenses														
	a. Depreciation (D)		192,468	192,468	192,468	192,468	192,468	192,468	192,468	192,468	192,468	192,468	192,468	192,468	2,309,616
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		446,857	445,621	444,387	443,151	441,917	440,681	442,712	441,460	440,209	438,957	437,706	436,454	5,300,112
	a. Recoverable Costs Allocated to Energy		446,857	445,621	444,387	443,151	441,917	440,681	442,712	441,460	440,209	438,957	437,706	436,454	5,300,112
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		446,857	445,621	444,387	443,151	441,917	440,681	442,712	441,460	440,209	438,957	437,706	436,454	5,300,112
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$446,857	$445,621	$444,387	$443,151	$441,917	$440,681	$442,712	$441,460	$440,209	$438,957	$437,706	$436,454	$5,300,112

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.54 ($16,857,250), 312.54 ($38,069,546), 315.54 ($10,642,027), 316.54 ($687,934), and 315.40 ($558,103).
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 2.4%, 3.8%, 3.9%, 3.3%, and 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD System Reliability
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	
3.	Less: Accumulated Depreciation	(5,834,881)	(5,886,463)	(5,938,045)	(5,989,627)	(6,041,209)	(6,092,791)	(6,144,373)	(6,195,955)	(6,247,537)	(6,299,119)	(6,350,701)	(6,402,283)	(6,453,865)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$18,632,925	18,581,343	18,529,761	18,478,179	18,426,597	18,375,015	18,323,433	18,271,851	18,220,269	18,168,687	18,117,105	18,065,523	18,013,941	
6.	Average Net Investment		18,607,134	18,555,552	18,503,970	18,452,388	18,400,806	18,349,224	18,297,642	18,246,060	18,194,478	18,142,896	18,091,314	18,039,732	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$92,470	$92,213	$91,957	$91,701	$91,444	$91,188	$91,635	$91,376	$91,118	$90,860	$90,601	$90,343	$1,096,906
	b. Debt Component Grossed Up For Taxes (C)		26,932	26,858	26,783	26,708	26,634	26,559	27,334	27,257	27,180	27,102	27,025	26,948	323,320
8.	Investment Expenses														
	a. Depreciation (D)		51,582	51,582	51,582	51,582	51,582	51,582	51,582	51,582	51,582	51,582	51,582	51,582	618,984
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		170,984	170,653	170,322	169,991	169,660	169,329	170,551	170,215	169,880	169,544	169,208	168,873	2,039,210
	a. Recoverable Costs Allocated to Energy		170,984	170,653	170,322	169,991	169,660	169,329	170,551	170,215	169,880	169,544	169,208	168,873	2,039,210
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		170,984	170,653	170,322	169,991	169,660	169,329	170,551	170,215	169,880	169,544	169,208	168,873	2,039,210
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$170,984	$170,653	$170,322	$169,991	$169,660	$169,329	$170,551	$170,215	$169,880	$169,544	$169,208	$168,873	$2,039,210

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.45 ($23,011,597) and 312.44 ($1,456,209).
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 2.5% and 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Mercury Air Toxics Standards (MATS)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	8,621,413	8,621,413	8,621,413	8,621,413	8,621,413	8,621,413	8,621,413	8,621,413	8,621,413	8,621,413	8,621,413	8,621,413	8,621,413	
3.	Less: Accumulated Depreciation	(1,687,707)	(1,710,003)	(1,732,299)	(1,754,595)	(1,776,891)	(1,799,187)	(1,821,483)	(1,843,779)	(1,866,075)	(1,888,371)	(1,910,667)	(1,932,963)	(1,955,259)	
4.	CWIP - Non-Interest Bearing	13,614	13,614	13,614	13,614	13,614	13,614	13,614	13,614	13,614	13,614	13,614	13,614	13,614	
5.	Net Investment (Lines 2 + 3 + 4)	$6,947,321	6,925,025	6,902,729	6,880,433	6,858,137	6,835,841	6,813,545	6,791,249	6,768,953	6,746,657	6,724,361	6,702,065	6,679,769	
6.	Average Net Investment		6,936,173	6,913,877	6,891,581	6,869,285	6,846,989	6,824,693	6,802,397	6,780,101	6,757,805	6,735,509	6,713,213	6,690,917	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$34,470	$34,359	$34,248	$34,137	$34,027	$33,916	$34,066	$33,955	$33,843	$33,731	$33,620	$33,508	$407,880
	b. Debt Component Grossed Up For Taxes (C)		10,040	10,007	9,975	9,943	9,910	9,878	10,162	10,128	10,095	10,062	10,028	9,995	120,223
8.	Investment Expenses														
	a. Depreciation (D)		22,296	22,296	22,296	22,296	22,296	22,296	22,296	22,296	22,296	22,296	22,296	22,296	267,552
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		66,806	66,662	66,519	66,376	66,233	66,090	66,524	66,379	66,234	66,089	65,944	65,799	795,655
	a. Recoverable Costs Allocated to Energy		66,806	66,662	66,519	66,376	66,233	66,090	66,524	66,379	66,234	66,089	65,944	65,799	795,655
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		66,806	66,662	66,519	66,376	66,233	66,090	66,524	66,379	66,234	66,089	65,944	65,799	795,655
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$66,806	$66,662	$66,519	$66,376	$66,233	$66,090	$66,524	$66,379	$66,234	$66,089	$65,944	$65,799	$795,655

Notes:

(A) Applicable depreciable base for Big Bend and Polk; accounts 312.44 ($3,427,481), 341.80 ($26,150), 315.40 ($1,226,949), 315.41 ($138,853), 315.42 ($138,853), 312.45 ($2,053,017), 312.46 ($1,242,315), 315.44 ($16,035), 315.45 ($40,217), 315.46 ($50,784), 311.40 ($13,216), 345.81 ($2,232), 312.54 ($210,295), and 395.00 ($35,018).

(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)

(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)

(D) Applicable depreciation rate is 3.0%, 2.2%, 3.7%, 3.5%, 3.3%, 2.5%, 3.3%, 3.2%, 3.1%, 3.5%, 2.9%, 3.3%, 3.8%, and 14.3%

(E) Line 9a x Line 10

(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

For Project: SO_2 Emissions Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Purchases/Transfers		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Auction Proceeds/Other		0	0	0	33	0	0	0	0	0	0	0	0	33
2.	Working Capital Balance														
	a. FERC 158.1 Allowance Inventory	$0	0	0	0	0	0	0	0	0	0	0	0	0	
	b. FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c. FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d. FERC 254.01 Regulatory Liabilities - Gains	(34,280)	(34,269)	(34,269)	(34,269)	(34,263)	(34,263)	(34,263)	(34,260)	(34,260)	(34,260)	(34,249)	(34,249)	(34,249)	
3.	Total Working Capital Balance	($34,280)	(34,269)	(34,269)	(34,269)	(34,263)	(34,263)	(34,263)	(34,260)	(34,260)	(34,260)	(34,249)	(34,249)	(34,249)	
4.	Average Net Working Capital Balance		($34,275)	($34,269)	($34,269)	($34,266)	($34,263)	($34,263)	($34,262)	($34,260)	($34,260)	($34,255)	($34,249)	($34,249)	
5.	Return on Average Net Working Capital Balance														
	a. Equity Component Grossed Up For Taxes (A)		($170)	($170)	($170)	($170)	($170)	($170)	($172)	($172)	($172)	($172)	($172)	($172)	($2,052)
	b. Debt Component Grossed Up For Taxes (B)		(50)	(50)	(50)	(50)	(50)	(50)	(51)	(51)	(51)	(51)	(51)	(51)	(606)
6.	Total Return Component		(220)	(220)	(220)	(220)	(220)	(220)	(223)	(223)	(223)	(223)	(223)	(223)	(2,658)
7.	Expenses:														
	a. Gains		0	0	0	(33)	0	0	0	0	0	0	0	0	(33)
	b. Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. SO_2 Allowance Expense		2	5	4	(6)	0	2	(1)	2	10	1	19	13	52
8.	Net Expenses (D)		2	5	4	(39)	0	2	(1)	2	10	1	19	13	19
9.	Total System Recoverable Expenses (Lines 6 + 8)		(218)	(215)	(216)	(259)	(220)	(218)	(224)	(221)	(213)	(222)	(204)	(210)	(2,639)
	a. Recoverable Costs Allocated to Energy		(218)	(215)	(216)	(259)	(220)	(218)	(224)	(221)	(213)	(222)	(204)	(210)	(2,639)
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		(218)	(215)	(216)	(259)	(220)	(218)	(224)	(221)	(213)	(222)	(204)	(210)	(2,640)
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Juris. Recoverable Costs (Lines 12 + 13)		($218)	($215)	($216)	($259)	($220)	($218)	($224)	($221)	($213)	($222)	($204)	($210)	($2,640)

Notes:
(A) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(B) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(C) Line 6 is reported on Schedule 7E.
(D) Line 8 is reported on Schedule 5E.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Gypsum Storage Facility
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0
	b. Clearings to Plant		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	21,467,359	21,467,359	21,467,359	21,467,359	21,467,359	21,467,359	21,467,359	21,467,359	21,467,359	21,467,359	21,467,359	21,467,359	21,467,359	
3.	Less: Accumulated Depreciation	(3,154,875)	(3,206,754)	(3,258,633)	(3,310,512)	(3,362,391)	(3,414,270)	(3,466,149)	(3,518,028)	(3,569,907)	(3,621,786)	(3,673,665)	(3,725,544)	(3,777,423)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$18,312,484	18,260,605	18,208,726	18,156,847	18,104,968	18,053,089	18,001,210	17,949,331	17,897,452	17,845,573	17,793,694	17,741,815	17,689,936	
6.	Average Net Investment		18,286,545	18,234,666	18,182,787	18,130,908	18,079,029	18,027,150	17,975,271	17,923,392	17,871,513	17,819,634	17,767,755	17,715,876	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$90,877	$90,619	$90,361	$90,103	$89,845	$89,587	$90,020	$89,760	$89,501	$89,241	$88,981	$88,721	$1,077,616
	b. Debt Component Grossed Up For Taxes (C)		26,468	26,393	26,318	26,243	26,168	26,093	26,852	26,775	26,697	26,620	26,542	26,465	317,634
8.	Investment Expenses														
	a. Depreciation (D)		51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	622,548
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		169,224	168,891	168,558	168,225	167,892	167,559	168,751	168,414	168,077	167,740	167,402	167,065	2,017,798
	a. Recoverable Costs Allocated to Energy		169,224	168,891	168,558	168,225	167,892	167,559	168,751	168,414	168,077	167,740	167,402	167,065	2,017,798
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		169,224	168,891	168,558	168,225	167,892	167,559	168,751	168,414	168,077	167,740	167,402	167,065	2,017,798
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$169,224	$168,891	$168,558	$168,225	$167,892	$167,559	$168,751	$168,414	$168,077	$167,740	$167,402	$167,065	$2,017,798

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.40
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 2.9%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Coal Combustion Residual Rule (CCR Rule)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$8,787	$9,800	$3,433	$8,328	$14,211	$23,138	$50,951	$136,353	$155,493	$217,686	$64,523	$671,774	$1,364,478
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	930,303	930,303	930,303	930,303	930,303	930,303	930,303	930,303	930,303	930,303	930,303	930,303	930,303	
3.	Less: Accumulated Depreciation	(50,121)	(52,425)	(54,729)	(57,033)	(59,337)	(61,641)	(63,945)	(66,249)	(68,553)	(70,857)	(73,161)	(75,465)	(77,769)	
4.	CWIP - Non-Interest Bearing	291,146	299,934	309,734	313,167	321,494	335,706	358,844	409,795	546,148	701,640	919,327	983,850	1,655,624	
5.	Net Investment (Lines 2 + 3 + 4)	1,171,328	1,177,812	1,185,308	1,186,437	1,192,460	1,204,368	1,225,202	1,273,849	1,407,898	1,561,086	1,776,469	1,838,688	2,508,158	
6.	Average Net Investment		1,174,570	1,181,560	1,185,873	1,189,449	1,198,414	1,214,785	1,249,526	1,340,873	1,484,492	1,668,778	1,807,578	2,173,423	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$5,837	$5,872	$5,893	$5,911	$5,956	$6,037	$6,258	$6,715	$7,434	$8,357	$9,052	$10,885	$84,207
	b. Debt Component Grossed Up For Taxes (C)		1,700	1,710	1,716	1,722	1,735	1,758	1,867	2,003	2,218	2,493	2,700	3,247	24,869
8.	Investment Expenses														
	a. Depreciation (D)		2,304	2,304	2,304	2,304	2,304	2,304	2,304	2,304	2,304	2,304	2,304	2,304	27,648
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		9,841	9,886	9,913	9,937	9,995	10,099	10,429	11,022	11,956	13,154	14,056	16,436	136,724
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		9,841	9,886	9,913	9,937	9,995	10,099	10,429	11,022	11,956	13,154	14,056	16,436	136,724
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		9,841	9,886	9,913	9,937	9,995	10,099	10,429	11,022	11,956	13,154	14,056	16,436	136,724
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$9,841	$9,886	$9,913	$9,937	$9,995	$10,099	$10,429	$11,022	$11,956	$13,154	$14,056	$16,436	$136,724

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.40 ($261,568) and 312.44 ($668,735).
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 2.9% and 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Coal Combustion Residuals (CCR Rule - Phase II)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$17,515	$23,385	$29,109	$30,920	$43,592	$62,914	$50,083	$36,283	$29,984	$33,797	$89,006	$27,343	$473,932
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	681,830	699,345	722,731	751,839	782,759	826,352	889,266	939,349	975,632	1,005,616	1,039,413	1,128,419	1,155,762	
5.	Net Investment (Lines 2 + 3 + 4)	$681,830	699,345	722,731	751,839	782,759	826,352	889,266	939,349	975,632	1,005,616	1,039,413	1,128,419	1,155,762	
6.	Average Net Investment		690,588	711,038	737,285	767,299	804,555	857,809	914,307	957,491	990,624	1,022,515	1,083,916	1,142,090	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$3,432	$3,534	$3,664	$3,813	$3,998	$4,263	$4,579	$4,795	$4,961	$5,121	$5,428	$5,720	$53,308
	b. Debt Component Grossed Up For Taxes (C)		1,000	1,029	1,067	1,111	1,165	1,242	1,366	1,430	1,480	1,527	1,619	1,706	15,742
8.	Investment Expenses														
	a. Depreciation (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		4,432	4,563	4,731	4,924	5,163	5,505	5,945	6,225	6,441	6,648	7,047	7,426	69,050
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		4,432	4,563	4,731	4,924	5,163	5,505	5,945	6,225	6,441	6,648	7,047	7,426	69,050
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		4,432	4,563	4,731	4,924	5,163	5,505	5,945	6,225	6,441	6,648	7,047	7,426	69,050
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$4,432	$4,563	$4,731	$4,924	$5,163	$5,505	$5,945	$6,225	$6,441	$6,648	$7,047	$7,426	$69,050

Notes:
(A) Applicable depreciable base for Big Bend; accounts TBD depending on type of plant added
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is TBD depending on type of plant added
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend ELG Compliance
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$3,416	$4,038	$22,491	$20,109	$23,361	$24,716	$21,764	$13,273	$18,927	$20,949	$204,473	$2,005,394	$2,382,912
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	139,594	143,010	147,048	169,538	189,648	213,009	237,725	259,489	272,762	291,690	312,639	517,112	2,522,506	
5.	Net Investment (Lines 2 + 3 + 4)	$139,594	143,010	147,048	169,538	189,648	213,009	237,725	259,489	272,762	291,690	312,639	517,112	2,522,506	
6.	Average Net Investment		141,302	145,029	158,293	179,593	201,328	225,367	248,607	266,126	282,226	302,164	414,875	1,519,809	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$702	$721	$787	$893	$1,001	$1,120	$1,245	$1,333	$1,413	$1,513	$2,078	$7,611	$20,417
	b. Debt Component Grossed Up For Taxes (C)		205	210	229	260	291	326	371	398	422	451	620	2,270	6,053
8.	Investment Expenses														
	a. Depreciation (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		907	931	1,016	1,153	1,292	1,446	1,616	1,731	1,835	1,964	2,698	9,881	26,470
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		907	931	1,016	1,153	1,292	1,446	1,616	1,731	1,835	1,964	2,698	9,881	26,470
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		907	931	1,016	1,153	1,292	1,446	1,616	1,731	1,835	1,964	2,698	9,881	26,470
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$907	$931	$1,016	$1,153	$1,292	$1,446	$1,616	$1,731	$1,835	$1,964	$2,698	$9,881	$26,470

Notes:
(A) Applicable depreciable base for Big Bend; accounts TBD depending on type of plant added
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is TBD depending on type of plant added
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Section 316(b) Impingement Mortality
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$3,886	$7,498	$81,696	$22,094	$22,934	$81,636	$38,199	$31,738	$453,050	$67,533	$40,932	$162,135	$1,013,331
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	59,601	63,487	70,985	152,681	174,776	197,709	279,345	317,544	349,282	802,332	869,865	910,796	1,072,932	
5.	Net Investment (Lines 2 + 3 + 4)	$59,601	63,487	70,985	152,681	174,776	197,709	279,345	317,544	349,282	802,332	869,865	910,796	1,072,932	
6.	Average Net Investment		61,544	67,236	111,833	163,728	186,242	238,527	298,445	333,413	575,807	836,098	890,331	991,864	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$306	$334	$556	$814	$926	$1,185	$1,495	$1,670	$2,884	$4,187	$4,459	$4,967	$23,783
	b. Debt Component Grossed Up For Taxes (C)		89	97	162	237	270	345	446	498	860	1,249	1,330	1,482	7,065
8.	Investment Expenses														
	a. Depreciation (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		395	431	718	1,051	1,196	1,530	1,941	2,168	3,744	5,436	5,789	6,449	30,848
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		395	431	718	1,051	1,196	1,530	1,941	2,168	3,744	5,436	5,789	6,449	30,848
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		395	431	718	1,051	1,196	1,530	1,941	2,168	3,744	5,436	5,789	6,449	30,848
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$395	$431	$718	$1,051	$1,196	$1,530	$1,941	$2,168	$3,744	$5,436	$5,789	$6,449	$30,848

Notes:
(A) Applicable depreciable base for Big Bend; accounts TBD depending on type of plant added
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is TBD depending on type of plant added
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of Final True-up Amount for the Period
January 2020 to June 2020

Calculation of Revenue Requirement Rate of Return
(in Dollars)

	(1) Jurisdictional Rate Base **Actual May 2019** ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 1,897,597	31.57%	4.89%	1.5435%
Short Term Debt	211,895	3.52%	2.97%	0.1047%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	94,966	1.58%	2.38%	0.0376%
Common Equity	2,598,065	43.22%	10.25%	4.4297%
Accum. Deferred Inc. Taxes & Zero Cost ITC's	1,125,550	18.72%	0.00%	0.0000%
Deferred ITC - Weighted Cost	83,633	1.39%	7.98%	0.1110%
Total	$ 6,011,707	100.00%		6.23%

ITC split between Debt and Equity:

Long Term Debt	$ 1,897,597	Long Term Debt	46.00%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	2,598,065	Equity - Common	54.00%
Total	$ 4,495,662	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = 0.1110% * 46.00%	0.0511%
Equity = 0.1110% * 54.00%	0.0599%
Weighted Cost	0.1110%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.4297%
Deferred ITC - Weighted Cost	0.0599%
	4.4896%
Times Tax Multiplier	1.32830
Total Equity Component	**5.9635%**

Total Debt Cost Rate:

Long Term Debt	1.5435%
Short Term Debt	0.1047%
Customer Deposits	0.0376%
Deferred ITC - Weighted Cost	0.0511%
Total Debt Component	**1.7369%**
	7.7004%

Notes:

Column (1) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2017 Base Rates Settlement Agreement Dated September 27, 2017.
Column (2) - Column (1) / Total Column (1)
Column (3) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2017 Base Rates Settlement Agreement Dated September 27, 2017.
Column (4) - Column (2) x Column (3)

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
July 2020 to December 2020

Calculation of Revenue Requirement Rate of Return
(In Dollars)

	(1) Jurisdictional Rate Base **Actual May 2020** ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 2,209,385	33.98%	4.71%	1.6003%
Short Term Debt	196,185	3.02%	2.19%	0.0661%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	93,706	1.44%	2.36%	0.0340%
Common Equity	2,801,776	43.08%	10.25%	4.4160%
Accum. Deferred Inc. Taxes & Zero Cost ITC's	1,034,859	15.91%	0.00%	0.0000%
Deferred ITC - Weighted Cost	166,903	2.57%	7.81%	0.2005%
Total	$ 6,502,815	100.00%		6.32%

ITC split between Debt and Equity:

Long Term Debt	$ 2,209,385	Long Term Debt	46.00%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	2,801,776	Equity - Common	54.00%
Total	$ 5,011,162	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = 0.2005% * 46.00%	0.0922%
Equity = 0.2005% * 54.00%	0.1083%
Weighted Cost	0.2005%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.4160%
Deferred ITC - Weighted Cost	0.1083%
	4.5243%
Times Tax Multiplier	1.32830
Total Equity Component	6.0096%

Total Debt Cost Rate:

Long Term Debt	1.6003%
Short Term Debt	0.0661%
Customer Deposits	0.0340%
Deferred ITC - Weighted Cost	0.0922%
Total Debt Component	1.7926%
	7.8022%

Notes:
Column (1) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2017 Base Rates Settlement Agreement Dated September 27, 2017.
Column (2) - Column (1) / Total Column (1)
Column (3) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2017 Base Rates Settlement Agreement Dated September 27, 2017.
Column (4) - Column (2) x Column (3)

EXHIBIT TO THE TESTIMONY OF
M. ASHLEY SIZEMORE

TAMPA ELECTRIC'S ENVIRONMENTAL COST RECOVERY

ACTUAL/ESTIMATED TRUE-UP

JANUARY 2021 THROUGH DECEMBER 2021

TAMPA ELECTRIC COMPANY
DOCKET NO. 20210007-EI
EXHIBIT NO. MAS-2
FILED: 07/30/2021

INDEX

TAMPA ELECTRIC COMPANY

ENVIRONMENTAL COST RECOVERY CLAUSE

ACTUAL/ESTIMATED TRUE-UP AMOUNT

FOR THE PERIOD

JANUARY 2021 THROUGH DECEMBER 2021

FORMS 42-1E THROUGH 42-9E

<u>Tampa Electric Company</u>
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021
(in Dollars)

Form 42 - 1E

Line		Period Amount
1.	Over/(Under) Recovery for the Current Period (Form 42-2E, Line 5)	($4,286,378)
2.	Interest Provision (Form 42-2E, Line 6)	(3,245)
3.	Sum of Current Period Adjustments (Form 42-2E, Line 10)	0
4.	Current Period True-Up Amount to be Refunded/(Recovered) In the Projection Period January 2022 to December 2022 (Lines 1 + 2 + 3)	($4,289,623)

Form 42 - 2E

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Current Period True-Up Amount
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	ECRC Revenues (net of Revenue Taxes)	$4,084,708	$3,662,094	$3,642,808	$3,959,659	$4,362,891	$5,015,784	$5,103,097	$5,071,141	$5,310,054	$4,802,861	$4,025,337	$3,828,643	$52,869,078
2.	True-Up Provision	(321,105)	(321,105)	(321,105)	(321,105)	(321,105)	(321,105)	(321,105)	(321,105)	(321,105)	(321,105)	(321,105)	(321,106)	(3,853,261)
3.	ECRC Revenues Applicable to Period (Lines 1 + 2)	3,763,603	3,340,989	3,321,703	3,638,554	4,041,786	4,694,679	4,781,992	4,750,036	4,988,949	4,481,756	3,704,232	3,507,537	49,015,817
4.	Jurisdictional ECRC Costs													
	a. O & M Activities (Form 42-5E, Line 9)	1,247,596	569,096	1,907,372	1,258,012	1,440,778	1,146,917	453,640	250,262	249,262	246,415	247,262	234,080	9,250,692
	b. Capital Investment Projects (Form 42-7E, Line 9)	3,670,420	3,666,136	3,665,085	3,663,034	3,655,660	3,652,451	3,654,655	3,658,139	3,665,810	3,684,891	3,707,567	3,707,654	44,051,502
	c. Total Jurisdictional ECRC Costs	4,918,016	4,235,232	5,572,457	4,921,046	5,096,438	4,799,368	4,108,295	3,908,401	3,915,072	3,931,306	3,954,829	3,941,734	53,302,194
5.	Over/(Under) Recovery (Line 3 - Line 4c)	(1,154,413)	(894,243)	(2,250,754)	(1,282,492)	(1,054,652)	(104,689)	673,697	841,635	1,073,877	550,450	(250,597)	(434,197)	(4,286,378)
6.	Interest Provision (Form 42-3E, Line 10)	(3)	(66)	(159)	(275)	(214)	(227)	(748)	(914)	(505)	(143)	8	1	(3,245)
7.	Beginning Balance True-Up & Interest Provision	(3,853,261)	(4,686,572)	(5,259,776)	(7,189,584)	(8,151,246)	(8,885,007)	(8,668,818)	(7,674,764)	(6,512,938)	(5,118,461)	(4,247,049)	(4,176,533)	(3,853,261)
	a. Deferred True-Up from January to December 2020 (Order No. PSC-2020-0433-FOF-EI)	4,237,191	4,237,191	4,237,191	4,237,191	4,237,191	4,237,191	4,237,191	4,237,191	4,237,191	4,237,191	4,237,191	4,237,191	4,237,191
8.	True-Up Collected/(Refunded) (see Line 2)	321,105	321,105	321,105	321,105	321,105	321,105	321,105	321,105	321,105	321,105	321,105	321,106	3,853,261
9.	End of Period Total True-Up (Lines 5+6+7+7a+8)	(449,381)	(1,022,585)	(2,952,393)	(3,914,055)	(4,647,816)	(4,431,627)	(3,437,573)	(2,275,747)	(881,270)	(9,858)	60,658	(52,432)	(52,432)
10.	Adjustment to Period True-Up Including Interest	0	0	0	0	0	0	0	0	0	0	0	0	0
11.	End of Period Total True-Up (Lines 9 + 10)	($449,381)	($1,022,585)	($2,952,393)	($3,914,055)	($4,647,816)	($4,431,627)	($3,437,573)	($2,275,747)	($881,270)	($9,858)	$60,658	($52,432)	($52,432)

DOCKET NO. 20210007-EI
ECRC 2021 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT NO. MAS-2, DOCUMENT NO. 2, PAGE 1 OF 1

Form 42 - 3E

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Interest Provision
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Beginning True-Up Amount (Form 42-2A, Line 7 + 7a + 10)	$383,930	($449,381)	($1,022,585)	($2,952,393)	($3,914,055)	($4,647,816)	($4,431,627)	($3,437,573)	($2,275,747)	($881,270)	($9,858)	$60,658	
2.	Ending True-Up Amount Before Interest	(449,378)	(1,022,519)	(2,952,234)	(3,913,780)	(4,647,602)	(4,431,400)	(3,436,825)	(2,274,833)	(880,765)	(9,715)	60,650	(52,433)	
3.	Total of Beginning & Ending True-Up (Lines 1 + 2)	(65,448)	(1,471,900)	(3,974,819)	(6,866,173)	(8,561,657)	(9,079,216)	(7,868,452)	(5,712,406)	(3,156,512)	(890,985)	50,792	8,225	
4.	Average True-Up Amount (Line 3 x 1/2)	(32,724)	(735,950)	(1,987,410)	(3,433,087)	(4,280,829)	(4,539,608)	(3,934,226)	(2,856,203)	(1,578,256)	(445,493)	25,396	4,113	
5.	Interest Rate (First Day of Reporting Business Month)	0.10%	0.12%	0.09%	0.11%	0.07%	0.04%	0.08%	0.38%	0.38%	0.38%	0.38%	0.38%	
6.	Interest Rate (First Day of Subsequent Business Month)	0.12%	0.09%	0.11%	0.07%	0.04%	0.08%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	
7.	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	0.22%	0.21%	0.20%	0.18%	0.11%	0.12%	0.46%	0.76%	0.76%	0.76%	0.76%	0.76%	
8.	Average Interest Rate (Line 7 x 1/2)	0.110%	0.105%	0.100%	0.090%	0.055%	0.060%	0.230%	0.380%	0.380%	0.380%	0.380%	0.380%	
9.	Monthly Average Interest Rate (Line 8 x 1/12)	0.009%	0.009%	0.008%	0.008%	0.005%	0.005%	0.019%	0.032%	0.032%	0.032%	0.032%	0.032%	
10.	Interest Provision for the Month (Line 4 x Line 9)	($3)	($66)	($159)	($275)	($214)	($227)	($748)	($914)	($505)	($143)	$8	$1	($3,245)

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Form 42 - 4E

Variance Report of O & M Activities
(In Dollars)

Line		(1) Actual / Estimated	(2) Original Projection	(3) Variance Amount	(4) Variance Percent
1.	Description of O&M Activities				
	a. Big Bend Unit 3 Flue Gas Desulfurization Integration	0	0	0	0.0%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0.0%
	c. SO_2 Emissions Allowances	41	15	26	170.2%
	d. Big Bend Units 1 & 2 FGD	8,966	0	8,966	100.0%
	e. Big Bend PM Minimization and Monitoring	218,747	252,000	(33,253)	-13.2%
	f. Big Bend NO_x Emissions Reduction	2,950	2,028	922	45.5%
	g. NPDES Annual Surveillance Fees	34,500	23,500	11,000	46.8%
	h. Gannon Thermal Discharge Study	0	0	0	0.0%
	i. Polk NO_x Emissions Reduction	595	0	595	100.0%
	j. Bayside SCR Consumables	139,173	119,000	20,173	17.0%
	k. Big Bend Unit 4 SOFA	0	0	0	0.0%
	l. Big Bend Unit 1 Pre-SCR	0	0	0	0.0%
	m. Big Bend Unit 2 Pre-SCR	0	0	0	0.0%
	n. Big Bend Unit 3 Pre-SCR	0	0	0	0.0%
	o. Clean Water Act Section 316(b) Phase II Study	6,020	45,000	(38,980)	-86.6%
	p. Arsenic Groundwater Standard Program	0	36,000	(36,000)	-100.0%
	q. Big Bend 1 SCR	0	0	0	0.0%
	r. Big Bend 2 SCR	106,340	122,020	(15,680)	-12.9%
	s. Big Bend 3 SCR	542,672	524,097	18,575	3.5%
	t. Big Bend 4 SCR	893,479	1,077,230	(183,752)	-17.1%
	u. Mercury Air Toxics Standards	5,494	3,000	2,494	83.1%
	v. Greenhouse Gas Reduction Program	93,149	93,528	(379)	-0.4%
	w. Big Bend Gypsum Storage Facility	621,996	1,177,899	(555,903)	-47.2%
	x. Coal Combustion Residuals (CCR) Rule	763,222	0	763,222	100.0%
	y. Big Bend ELG Compliance	0	4,800	(4,800)	-100.0%
	z. CCR Rule - Phase II	5,813,349	0	5,813,349	100.0%
	aa. Big Bend Unit 1 Sec. 316(b) Impingement Mortality	0	0	0	0.0%
2.	Total Investment Projects - Recoverable Costs	$9,250,693	$3,480,118	$5,770,575	165.8%
3.	Recoverable Costs Allocated to Energy	$9,210,173	$3,375,618	$5,834,555	172.8%
4.	Recoverable Costs Allocated to Demand	$40,520	$104,500	($63,980)	-61.2%

Notes:
Column (1) is the End of Period Totals on Form 42-5E.
Column (2) is the approved projected amount in accordance with FPSC Order No. PSC-2020-0433-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Form 42 - 5E

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

O&M Activities
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	Description of O&M Activities															
	a. Big Bend Unit 3 Flue Gas Desulfurization Integration	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	c. SO_2 Emissions Allowances	(6)	11	9	(11)	5	14	(5)	7	7	(5)	7	7	41		41
	d. Big Bend Units 1 & 2 FGD	176	188	945	2,398	464	794	1,000	1,000	1,000	1,000	0	0	8,966		8,966
	e. Big Bend PM Minimization and Monitoring	17,045	4,150	44,199	(2,952)	26,981	16,900	18,500	18,500	18,500	18,500	18,500	19,923	218,747		218,747
	f. Big Bend NO_x Emissions Reduction	0	0	2,950	0	0	0	0	0	0	0	0	0	2,950		2,950
	g. NPDES Annual Surveillance Fees	0	34,500	0	0	0	0	0	0	0	0	0	0	34,500	$34,500	
	h. Gannon Thermal Discharge Study	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	i. Polk NO_x Emissions Reduction	519	76	0	0	0	0	0	0	0	0	0	0	595		595
	j. Bayside SCR and Ammonia	11,422	14,882	17,237	15,349	16,033	3,250	12,000	12,000	11,000	10,000	8,000	8,000	139,173		139,173
	k. Big Bend Unit 4 SOFA	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	l. Big Bend Unit 1 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	m. Big Bend Unit 2 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	n. Big Bend Unit 3 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	o. Clean Water Act Section 316(b) Phase II Study	(1,368)	1,006	200	400	218	0	0	0	0	0	2,500	3,065	6,020	6,020	
	p. Arsenic Groundwater Standard Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	q. Big Bend 1 SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	r. Big Bend 2 SCR	15,753	9,249	6,312	91	78	417	14,216	13,361	14,964	31,900	0	0	106,340		106,340
	s. Big Bend 3 SCR	40,305	41,595	16,619	5,616	15,451	90,744	39,638	34,892	34,495	37,843	110,731	74,745	542,672		542,672
	t. Big Bend 4 SCR	99,349	89,285	88,800	42,513	61,380	176,163	75,768	77,978	76,773	54,653	15,000	35,817	893,479		893,479
	u. Mercury Air Toxics Standards	0	0	5,539	0	(45)	0	0	0	0	0	0	0	5,494		5,494
	v. Greenhouse Gas Reduction Program	0	0	0	0	93,149	0	0	0	0	0	0	0	93,149		93,149
	w. Big Bend Gypsum Storage Facility (East 40)	7,164	14,525	1,005	13,307	10,773	20,080	92,524	92,524	92,524	92,524	92,524	92,524	621,996		621,996
	x. Coal Combustion Residuals (CCR) Rule - Phase I	516,830	(392,842)	483,934	2,758	0	152,542	0	0	0	0	0	0	763,222		763,222
	y. Big Bend ELG Compliance	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	z. Coal Combustion Residuals (CCR) Rule - Phase II	540,408	752,471	1,239,623	1,178,542	1,216,291	686,013	200,000	0	0	0	0	0	5,813,349		5,813,349
	aa. Big Bend Unit 1 Sec. 316(b) Impingement Mortality	0	0	0	0	0	0	0	0	0	0	0	0	0		0
2.	Total of O&M Activities	1,247,596	569,096	1,907,372	1,258,012	1,440,778	1,146,917	453,640	250,262	249,262	246,415	247,262	234,080	9,250,693	$40,520	$9,210,173
3.	Recoverable Costs Allocated to Energy	1,248,964	533,590	1,907,172	1,257,612	1,440,560	1,146,917	453,640	250,262	249,262	246,415	244,762	231,015	9,210,173		
4.	Recoverable Costs Allocated to Demand	(1,368)	35,506	200	400	218	0	0	0	0	0	2,500	3,065	40,520		
5.	Retail Energy Jurisdictional Factor	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
6.	Retail Demand Jurisdictional Factor	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
7.	Jurisdictional Energy Recoverable Costs (A)	1,248,964	533,590	1,907,172	1,257,612	1,440,560	1,146,917	453,640	250,262	249,262	246,415	244,762	231,015	9,210,172		
8.	Jurisdictional Demand Recoverable Costs (B)	(1,368)	35,506	200	400	218	0	0	0	0	0	2,500	3,065	40,521		
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$1,247,596	$569,096	$1,907,372	$1,258,012	$1,440,778	$1,146,917	$453,640	$250,262	249,262	246,415	$247,262	$234,080	$9,250,693		

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Form 42 - 6E

Variance Report of Capital Investment Projects - Recoverable Costs
(In Dollars)

Line		(1) Actual / Estimated	(2) Original Projection	(3) Variance Amount	(4) Variance Percent
1.	Description of Investment Projects				
	a. Big Bend Unit 3 Flue Gas Desulfurization Integration	$903,783	$906,095	($2,312)	-0.3%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	192,990	193,042	(52)	0.0%
	c. Big Bend Unit 4 Continuous Emissions Monitors	45,522	45,598	(76)	-0.2%
	d. Big Bend Fuel Oil Tank # 1 Upgrade	63,892	63,896	(4)	0.0%
	e. Big Bend Fuel Oil Tank # 2 Upgrade	105,079	105,098	(19)	0.0%
	f. Big Bend Unit 1 Classifier Replacement	69,128	69,201	(73)	-0.1%
	g. Big Bend Unit 2 Classifier Replacement	50,424	50,482	(58)	-0.1%
	h. Big Bend Section 114 Mercury Testing Platform	7,943	7,958	(15)	-0.2%
	i. Big Bend Units 1 & 2 FGD	5,431,446	5,440,931	(9,485)	-0.2%
	j. Big Bend FGD Optimization and Utilization	1,503,371	1,507,233	(3,862)	-0.3%
	k. Big Bend NO_x Emissions Reduction	485,706	487,214	(1,508)	-0.3%
	l. Big Bend PM Minimization and Monitoring	1,680,736	1,684,675	(3,939)	-0.2%
	m. Polk NO_x Emissions Reduction	103,219	103,428	(209)	-0.2%
	n. Big Bend Unit 4 SOFA	185,038	185,486	(448)	-0.2%
	o. Big Bend Unit 1 Pre-SCR	124,987	125,229	(242)	-0.2%
	p. Big Bend Unit 2 Pre-SCR	119,909	120,162	(253)	-0.2%
	q. Big Bend Unit 3 Pre-SCR	216,230	216,730	(500)	-0.2%
	r. Big Bend Unit 1 SCR	7,151,546	7,165,809	(14,263)	-0.2%
	s. Big Bend Unit 2 SCR	7,876,719	7,893,828	(17,109)	-0.2%
	t. Big Bend Unit 3 SCR	6,415,803	6,429,857	(14,054)	-0.2%
	u. Big Bend Unit 4 SCR	5,168,642	5,199,976	(31,334)	-0.6%
	v. Big Bend FGD System Reliability	2,007,420	2,013,174	(5,754)	-0.3%
	w. Mercury Air Toxics Standards	781,102	783,036	(1,934)	-0.2%
	x. $S0_2$ Emissions Allowances	(2,688)	(2,688)	0	0.0%
	y. Big Bend Gypsum Storage Facility	1,985,437	1,991,084	(5,647)	-0.3%
	z. Big Bend Coal Combustion Residual Rule (CCR Rule)	325,512	362,933	(37,421)	-10.3%
	aa. Coal Combustion Residuals (CCR-Phase II)	128,327	328,169	(199,842)	-60.9%
	ab. Big Bend ELG Compliance	439,715	782,650	(342,935)	-43.8%
	ac. Big Bend Unit 1 Sec. 316(b) Impingement Mortality	484,564	452,502	32,062	7.1%
2.	Total Investment Projects - Recoverable Costs	$44,051,502	$44,712,788	($661,286)	-1.5%
3.	Recoverable Costs Allocated to Energy	$42,504,413	$42,617,540	($113,127)	-0.3%
4.	Recoverable Costs Allocated to Demand	$1,547,089	$2,095,248	($548,159)	-26.2%

Notes:
Column (1) is the End of Period Totals on Form 42-7E.
Column (2) is the approved projected amount in accordance with FPSC Order No. PSC-2020-0433-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Form 42-7E

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line		Description (A)		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	a.	Big Bend Unit 3 Flue Gas Desulfurization Integration	1	$76,352	$76,163	$75,975	$75,786	$75,598	$75,409	$75,221	$75,033	$74,844	$74,656	$74,467	$74,279	$903,783		$903,783
	b.	Big Bend Units 1 and 2 Flue Gas Conditioning	2	17,770	17,665	17,559	17,454	17,349	17,243	17,138	17,031	16,926	16,821	12,287	7,747	192,990		192,990
	c.	Big Bend Unit 4 Continuous Emissions Monitors	3	3,877	3,862	3,847	3,831	3,816	3,801	3,786	3,771	3,756	3,740	3,725	3,710	45,522		45,522
	d.	Big Bend Fuel Oil Tank # 1 Upgrade	4	5,508	5,475	5,441	5,408	5,375	5,341	5,308	5,274	5,241	5,207	5,174	5,140	63,892	$63,892	
	e.	Big Bend Fuel Oil Tank # 2 Upgrade	5	9,060	9,004	8,949	8,894	8,839	8,784	8,728	8,674	8,618	8,564	8,508	8,457	105,079	105,079	
	f.	Big Bend Unit 1 Classifier Replacement	6	5,918	5,890	5,861	5,832	5,804	5,775	5,746	5,718	5,689	5,660	5,632	5,603	69,128		69,128
	g.	Big Bend Unit 2 Classifier Replacement	7	4,311	4,292	4,272	4,251	4,231	4,212	4,192	4,172	4,153	4,133	4,112	4,093	50,424		50,424
	h.	Big Bend Section 114 Mercury Testing Platform	8	673	670	669	666	665	663	661	659	657	655	654	651	7,943		7,943
	i.	Big Bend Units 1 & 2 FGD	9	462,034	460,323	458,612	456,900	455,188	453,476	451,765	450,053	448,341	446,629	444,918	443,207	5,431,446		5,431,446
	j.	Big Bend FGD Optimization and Utilization	10	126,993	126,682	126,371	126,060	125,748	125,436	125,125	124,814	124,503	124,191	123,880	123,568	1,503,371		1,503,371
	k.	Big Bend NO_x Emissions Reduction	11	40,842	40,775	40,709	40,642	40,575	40,509	40,442	40,376	40,309	40,242	40,176	40,109	485,706		485,706
	l.	Big Bend PM Minimization and Monitoring	12	142,249	141,851	141,454	141,056	140,658	140,260	139,863	139,465	139,067	138,669	138,271	137,873	1,680,736		1,680,736
	m.	Polk NO_x Emissions Reduction	13	8,761	8,732	8,703	8,674	8,645	8,616	8,587	8,558	8,529	8,500	8,471	8,443	103,219		103,219
	n.	Big Bend Unit 4 SOFA	14	15,650	15,608	15,566	15,524	15,483	15,441	15,399	15,357	15,316	15,274	15,231	15,189	185,038		185,038
	o.	Big Bend Unit 1 Pre-SCR	15	10,613	10,577	10,542	10,505	10,470	10,433	10,398	10,361	10,326	10,290	10,254	10,218	124,987		124,987
	p.	Big Bend Unit 2 Pre-SCR	16	10,167	10,136	10,104	10,072	10,041	10,008	9,976	9,945	9,913	9,881	9,849	9,817	119,909		119,909
	q.	Big Bend Unit 3 Pre-SCR	17	18,305	18,253	18,201	18,149	18,097	18,045	17,993	17,942	17,890	17,837	17,785	17,733	216,230		216,230
	r.	Big Bend Unit 1 SCR	18	607,075	605,055	603,034	601,013	598,993	596,972	594,952	592,931	590,910	588,891	586,870	584,850	7,151,546		7,151,546
	s.	Big Bend Unit 2 SCR	19	667,621	665,580	663,538	661,497	659,456	657,414	655,372	653,331	651,290	649,248	647,207	645,165	7,876,719		7,876,719
	t.	Big Bend Unit 3 SCR	20	543,711	542,063	540,416	538,768	537,122	535,474	533,827	532,179	530,531	528,885	527,237	525,590	6,415,803		6,415,803
	u.	Big Bend Unit 4 SCR	21	436,451	435,193	433,935	432,682	431,444	430,222	429,033	427,886	427,710	428,326	428,257	427,503	5,168,642		5,168,642
	v.	Big Bend FGD System Reliability	22	169,139	168,802	168,465	168,128	167,791	167,454	167,116	166,779	166,442	166,105	165,768	165,431	2,007,420		2,007,420
	w.	Mercury Air Toxics Standards	23	65,878	65,731	65,586	65,440	65,295	65,148	65,003	64,896	64,751	64,604	64,458	64,312	781,102		781,102
	x.	SO_2 Emissions Allowances (B)	24	(224)	(224)	(224)	(224)	(224)	(224)	(224)	(224)	(224)	(224)	(224)	(224)	(2,688)		(2,688)
	y.	Big Bend Gypsum Storage Facility	25	167,317	166,978	166,639	166,301	165,962	165,623	165,284	164,945	164,606	164,267	163,927	163,588	1,985,437		1,985,437
	z.	Big Bend Coal Combustion Residual Rule (CCR Rule)	26	21,293	24,405	25,609	26,297	26,387	26,540	26,902	27,193	27,178	27,163	33,300	33,245	325,512	325,512	
	aa.	Coal Combustion Residuals (CCR-Phase II)	27	7,601	7,769	7,902	7,928	7,968	8,017	8,885	10,593	12,293	13,130	18,137	18,104	128,327	128,327	
	ab.	Big Bend ELG Compliance	28	16,932	17,841	19,181	20,086	21,479	24,827	30,684	36,714	42,484	56,250	71,602	81,635	439,715	439,715	
	ac.	Big Bend Unit 1 Impingement Mortality - 316(b)	29	8,543	10,985	18,169	25,414	27,405	31,532	37,493	43,713	53,761	67,297	77,634	82,618	484,564	484,564	
2.		Total Investment Projects - Recoverable Costs		3,670,420	3,666,136	3,665,085	3,663,034	3,655,660	3,652,451	3,654,655	3,658,139	3,665,810	3,684,891	3,707,567	3,707,654	44,051,502	$1,547,089	$42,504,413
3.		Recoverable Costs Allocated to Energy		3,601,483	3,590,657	3,579,834	3,569,007	3,558,207	3,547,410	3,536,655	3,525,978	3,516,235	3,507,280	3,493,212	3,478,455	42,504,413		42,504,413
4.		Recoverable Costs Allocated to Demand		68,937	75,479	85,251	94,027	97,453	105,041	118,000	132,161	149,575	177,611	214,355	229,199	1,547,089	1,547,089	
5.		Retail Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
6.		Retail Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
7.		Jurisdictional Energy Recoverable Costs (C)		3,601,483	3,590,657	3,579,834	3,569,007	3,558,207	3,547,410	3,536,655	3,525,978	3,516,235	3,507,280	3,493,212	3,478,455	42,504,413		
8.		Jurisdictional Demand Recoverable Costs (D)		68,937	75,479	85,251	94,027	97,453	105,041	118,000	132,161	149,575	177,611	214,355	229,199	1,547,089		
9.		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)		$3,670,420	$3,666,136	$3,665,085	$3,663,034	$3,655,660	$3,652,451	$3,654,655	$3,658,139	$3,665,810	$3,684,891	$3,707,567	$3,707,654	$44,051,502		

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-8E, Line 9
(B) Project's Total Return Component on Form 42-8E, Line 6
(C) Line 3 x Line 5
(D) Line 4 x Line 6

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Flue Gas Desulfurization Integration
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	
3.	Less: Accumulated Depreciation	(6,478,449)	(6,507,287)	(6,536,125)	(6,564,963)	(6,593,801)	(6,622,639)	(6,651,477)	(6,680,315)	(6,709,153)	(6,737,991)	(6,766,829)	(6,795,667)	(6,824,505)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$7,284,814	$7,255,976	$7,227,138	$7,198,300	$7,169,462	$7,140,624	$7,111,786	$7,082,948	$7,054,110	$7,025,272	$6,996,434	$6,967,596	$6,938,758	
6.	Average Net Investment		7,270,395	7,241,557	7,212,719	7,183,881	7,155,043	7,126,205	7,097,367	7,068,529	7,039,691	7,010,853	6,982,015	6,953,177	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$37,569	$37,420	$37,271	$37,122	$36,973	$36,824	$36,675	$36,526	$36,377	$36,228	$36,079	$35,930	$440,994
	b. Debt Component Grossed Up For Taxes (C)		9,945	9,905	9,866	9,826	9,787	9,747	9,708	9,669	9,629	9,590	9,550	9,511	116,733
8.	Investment Expenses														
	a. Depreciation (D)		28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	346,056
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		76,352	76,163	75,975	75,786	75,598	75,409	75,221	75,033	74,844	74,656	74,467	74,279	903,783
	a. Recoverable Costs Allocated to Energy		76,352	76,163	75,975	75,786	75,598	75,409	75,221	75,033	74,844	74,656	74,467	74,279	903,783
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		76,352	76,163	75,975	75,786	75,598	75,409	75,221	75,033	74,844	74,656	74,467	74,279	903,783
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$76,352	$76,163	$75,975	$75,786	$75,598	$75,409	$75,221	$75,033	$74,844	$74,656	$74,467	$74,279	$903,783

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.45 ($13,435,775), 315.45 ($327,307), and 312.40 ($182).
(B) Line 6 x 6.2009% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 2.5%, 3.1%, and 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 Flue Gas Conditioning
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	
3.	Less: Accumulated Depreciation	(4,760,354)	(4,776,495)	(4,792,636)	(4,808,777)	(4,824,918)	(4,841,059)	(4,857,200)	(4,873,341)	(4,889,482)	(4,905,623)	(4,921,764)	(4,933,462)	(4,940,682)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$257,380	$241,239	$225,098	$208,957	$192,816	$176,675	$160,534	$144,393	$128,252	$112,111	$95,970	$84,272	$77,052	
6.	Average Net Investment		249,310	233,169	217,028	200,887	184,746	168,605	152,464	136,323	120,182	104,041	90,121	80,662	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,288	$1,205	$1,121	$1,038	$955	$871	$788	$704	$621	$538	$466	$417	$10,012
	b. Debt Component Grossed Up For Taxes (C)		341	319	297	275	253	231	209	186	164	142	123	110	2,650
8.	Investment Expenses														
	a. Depreciation (D)		16,141	16,141	16,141	16,141	16,141	16,141	16,141	16,141	16,141	16,141	11,698	7,220	180,328
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		17,770	17,665	17,559	17,454	17,349	17,243	17,138	17,031	16,926	16,821	12,287	7,747	192,990
	a. Recoverable Costs Allocated to Energy		17,770	17,665	17,559	17,454	17,349	17,243	17,138	17,031	16,926	16,821	12,287	7,747	192,990
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		17,770	17,665	17,559	17,454	17,349	17,243	17,138	17,031	16,926	16,821	12,287	7,747	192,990
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$17,770	$17,665	$17,559	$17,454	$17,349	$17,243	$17,138	$17,031	$16,926	$16,821	$12,287	$7,747	$192,990

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.41 ($2,676,217) and 312.42 ($2,341,517).
(B) Line 6 x 6.2009% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 4.0% and 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 Continuous Emissions Monitors
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	
3.	Less: Accumulated Depreciation	(625,325)	(627,635)	(629,945)	(632,255)	(634,565)	(636,875)	(639,185)	(641,495)	(643,805)	(646,115)	(648,425)	(650,735)	(653,045)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$240,886	$238,576	$236,266	$233,956	$231,646	$229,336	$227,026	$224,716	$222,406	$220,096	$217,786	$215,476	$213,166	
6.	Average Net Investment		239,731	237,421	235,111	232,801	230,491	228,181	225,871	223,561	221,251	218,941	216,631	214,321	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,239	$1,227	$1,215	$1,203	$1,191	$1,179	$1,167	$1,155	$1,143	$1,131	$1,119	$1,107	$14,076
	b. Debt Component Grossed Up For Taxes (C)		328	325	322	318	315	312	309	306	303	299	296	293	3,726
8.	Investment Expenses														
	a. Depreciation (D)		2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	27,720
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		3,877	3,862	3,847	3,831	3,816	3,801	3,786	3,771	3,756	3,740	3,725	3,710	45,522
	a. Recoverable Costs Allocated to Energy		3,877	3,862	3,847	3,831	3,816	3,801	3,786	3,771	3,756	3,740	3,725	3,710	45,522
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		3,877	3,862	3,847	3,831	3,816	3,801	3,786	3,771	3,756	3,740	3,725	3,710	45,522
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$3,877	$3,862	$3,847	$3,831	$3,816	$3,801	$3,786	$3,771	$3,756	$3,740	$3,725	$3,710	$45,522

Notes:
(A) Applicable depreciable base for Big Bend; account 315.44
(B) Line 6 x 6.2009% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 3.2%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 1 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	
3.	Less: Accumulated Depreciation	(436,102)	(441,225)	(446,348)	(451,471)	(456,594)	(461,717)	(466,840)	(471,963)	(477,086)	(482,209)	(487,332)	(492,455)	(497,578)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$61,476	$56,353	$51,230	$46,107	$40,984	$35,861	$30,738	$25,615	$20,492	$15,369	$10,246	$5,123	$0	
6.	Average Net Investment		58,915	53,792	48,669	43,546	38,423	33,300	28,177	23,054	17,931	12,808	7,685	2,562	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$304	$278	$251	$225	$199	$172	$146	$119	$93	$66	$40	$13	$1,906
	b. Debt Component Grossed Up For Taxes (C)		81	74	67	60	53	46	39	32	25	18	11	4	510
8.	Investment Expenses														
	a. Depreciation (D)		5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	61,476
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		5,508	5,475	5,441	5,408	5,375	5,341	5,308	5,274	5,241	5,207	5,174	5,140	63,892
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		5,508	5,475	5,441	5,408	5,375	5,341	5,308	5,274	5,241	5,207	5,174	5,140	63,892
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		5,508	5,475	5,441	5,408	5,375	5,341	5,308	5,274	5,241	5,207	5,174	5,140	63,892
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$5,508	$5,475	$5,441	$5,408	$5,375	$5,341	$5,308	$5,274	$5,241	$5,207	$5,174	$5,140	$63,892

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 6.2009% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 12.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 2 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	
3.	Less: Accumulated Depreciation	(717,286)	(725,712)	(734,138)	(742,564)	(750,990)	(759,416)	(767,842)	(776,268)	(784,694)	(793,120)	(801,546)	(809,972)	(818,401)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$101,115	$92,689	$84,263	$75,837	$67,411	$58,985	$50,559	$42,133	$33,707	$25,281	$16,855	$8,429	$0	
6.	Average Net Investment		96,902	88,476	80,050	71,624	63,198	54,772	46,346	37,920	29,494	21,068	12,642	4,215	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$501	$457	$414	$370	$327	$283	$239	$196	$152	$109	$65	$22	$3,135
	b. Debt Component Grossed Up For Taxes (C)		133	121	109	98	86	75	63	52	40	29	17	6	829
8.	Investment Expenses														
	a. Depreciation (D)		8,426	8,426	8,426	8,426	8,426	8,426	8,426	8,426	8,426	8,426	8,426	8,429	101,115
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		9,060	9,004	8,949	8,894	8,839	8,784	8,728	8,674	8,618	8,564	8,508	8,457	105,079
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		9,060	9,004	8,949	8,894	8,839	8,784	8,728	8,674	8,618	8,564	8,508	8,457	105,079
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		9,060	9,004	8,949	8,894	8,839	8,784	8,728	8,674	8,618	8,564	8,508	8,457	105,079
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$9,060	$9,004	$8,949	$8,894	$8,839	$8,784	$8,728	$8,674	$8,618	$8,564	$8,508	$8,457	$105,079

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 6.2009% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 12.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	
3.	Less: Accumulated Depreciation	(1,079,816)	(1,084,204)	(1,088,592)	(1,092,980)	(1,097,368)	(1,101,756)	(1,106,144)	(1,110,532)	(1,114,920)	(1,119,308)	(1,123,696)	(1,128,084)	(1,132,472)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$236,441	$232,053	$227,665	$223,277	$218,889	$214,501	$210,113	$205,725	$201,337	$196,949	$192,561	$188,173	$183,785	
6.	Average Net Investment		234,247	229,859	225,471	221,083	216,695	212,307	207,919	203,531	199,143	194,755	190,367	185,979	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,210	$1,188	$1,165	$1,142	$1,120	$1,097	$1,074	$1,052	$1,029	$1,006	$984	$961	$13,028
	b. Debt Component Grossed Up For Taxes (C)		320	314	308	302	296	290	284	278	272	266	260	254	3,444
8.	Investment Expenses														
	a. Depreciation (D)		4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	52,656
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		5,918	5,890	5,861	5,832	5,804	5,775	5,746	5,718	5,689	5,660	5,632	5,603	69,128
	a. Recoverable Costs Allocated to Energy		5,918	5,890	5,861	5,832	5,804	5,775	5,746	5,718	5,689	5,660	5,632	5,603	69,128
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		5,918	5,890	5,861	5,832	5,804	5,775	5,746	5,718	5,689	5,660	5,632	5,603	69,128
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$5,918	$5,890	$5,861	$5,832	$5,804	$5,775	$5,746	$5,718	$5,689	$5,660	$5,632	$5,603	$69,128

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 6.2009% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 4.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	
3.	Less: Accumulated Depreciation	(788,166)	(791,202)	(794,238)	(797,274)	(800,310)	(803,346)	(806,382)	(809,418)	(812,454)	(815,490)	(818,526)	(821,562)	(824,598)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$196,628	$193,592	$190,556	$187,520	$184,484	$181,448	$178,412	$175,376	$172,340	$169,304	$166,268	$163,232	$160,196	
6.	Average Net Investment		195,110	192,074	189,038	186,002	182,966	179,930	176,894	173,858	170,822	167,786	164,750	161,714	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,008	$993	$977	$961	$945	$930	$914	$898	$883	$867	$851	$836	$11,063
	b. Debt Component Grossed Up For Taxes (C)		267	263	259	254	250	246	242	238	234	230	225	221	2,929
8.	Investment Expenses														
	a. Depreciation (D)		3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	36,432
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		4,311	4,292	4,272	4,251	4,231	4,212	4,192	4,172	4,153	4,133	4,112	4,093	50,424
	a. Recoverable Costs Allocated to Energy		4,311	4,292	4,272	4,251	4,231	4,212	4,192	4,172	4,153	4,133	4,112	4,093	50,424
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		4,311	4,292	4,272	4,251	4,231	4,212	4,192	4,172	4,153	4,133	4,112	4,093	50,424
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
15	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$4,311	$4,292	$4,272	$4,251	$4,231	$4,212	$4,192	$4,172	$4,153	$4,133	$4,112	$4,093	$50,424

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 6.2009% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Section 114 Mercury Testing Platform
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	
3.	Less: Accumulated Depreciation	(62,419)	(62,711)	(63,003)	(63,295)	(63,587)	(63,879)	(64,171)	(64,463)	(64,755)	(65,047)	(65,339)	(65,631)	(65,923)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$58,318	$58,026	$57,734	$57,442	$57,150	$56,858	$56,566	$56,274	$55,982	$55,690	$55,398	$55,106	$54,814	
6.	Average Net Investment		58,172	57,880	57,588	57,296	57,004	56,712	56,420	56,128	55,836	55,544	55,252	54,960	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$301	$299	$298	$296	$295	$293	$292	$290	$289	$287	$286	$284	$3,510
	b. Debt Component Grossed Up For Taxes (C)		80	79	79	78	78	78	77	77	76	76	76	75	929
8.	Investment Expenses														
	a. Depreciation (D)		292	292	292	292	292	292	292	292	292	292	292	292	3,504
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		673	670	669	666	665	663	661	659	657	655	654	651	7,943
	a. Recoverable Costs Allocated to Energy		673	670	669	666	665	663	661	659	657	655	654	651	7,943
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		673	670	669	666	665	663	661	659	657	655	654	651	7,943
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$673	$670	$669	$666	$665	$663	$661	$659	$657	$655	$654	$651	$7,943

Notes:
(A) Applicable depreciable base for Big Bend; account 311.40
(B) Line 6 x 6.2009% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 2.9%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 FGD
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	
3.	Less: Accumulated Depreciation	(64,503,293)	(64,765,212)	(65,027,131)	(65,289,050)	(65,550,969)	(65,812,888)	(66,074,807)	(66,336,726)	(66,598,645)	(66,860,564)	(67,122,483)	(67,384,402)	(67,646,321)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$30,751,949	$30,490,030	$30,228,111	$29,966,192	$29,704,273	$29,442,354	$29,180,435	$28,918,516	$28,656,597	$28,394,678	$28,132,759	$27,870,840	$27,608,921	
6.	Average Net Investment		30,620,989	30,359,070	30,097,151	29,835,232	29,573,313	29,311,394	29,049,475	28,787,556	28,525,637	28,263,718	28,001,799	27,739,880	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$158,231	$156,878	$155,525	$154,171	$152,818	$151,464	$150,111	$148,757	$147,404	$146,050	$144,697	$143,344	$1,809,450
	b. Debt Component Grossed Up For Taxes (C)		41,884	41,526	41,168	40,810	40,451	40,093	39,735	39,377	39,018	38,660	38,302	37,944	478,968
8.	Investment Expenses														
	a. Depreciation (D)		261,919	261,919	261,919	261,919	261,919	261,919	261,919	261,919	261,919	261,919	261,919	261,919	3,143,028
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		462,034	460,323	458,612	456,900	455,188	453,476	451,765	450,053	448,341	446,629	444,918	443,207	5,431,446
	a. Recoverable Costs Allocated to Energy		462,034	460,323	458,612	456,900	455,188	453,476	451,765	450,053	448,341	446,629	444,918	443,207	5,431,446
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		462,034	460,323	458,612	456,900	455,188	453,476	451,765	450,053	448,341	446,629	444,918	443,207	5,431,446
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$462,034	$460,323	$458,612	$456,900	$455,188	$453,476	$451,765	$450,053	$448,341	$446,629	$444,918	$443,207	$5,431,446

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.46 ($94,929,061), 312.45 ($105,398), and 315.46 ($220,782).
(B) Line 6 x 6.2009% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 3.3%, 2.5%, and 3.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD Optimization and Utilization
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	
3.	Less: Accumulated Depreciation	(10,488,770)	(10,536,417)	(10,584,064)	(10,631,711)	(10,679,358)	(10,727,005)	(10,774,652)	(10,822,299)	(10,869,946)	(10,917,593)	(10,965,240)	(11,012,887)	(11,060,534)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$12,165,159	$12,117,512	$12,069,865	$12,022,218	$11,974,571	$11,926,924	$11,879,277	$11,831,630	$11,783,983	$11,736,336	$11,688,689	$11,641,042	$11,593,395	
6.	Average Net Investment		12,141,336	12,093,689	12,046,042	11,998,395	11,950,748	11,903,101	11,855,454	11,807,807	11,760,160	11,712,513	11,664,866	11,617,219	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$62,739	$62,493	$62,247	$62,001	$61,754	$61,508	$61,262	$61,016	$60,770	$60,523	$60,277	$60,031	$736,621
	b. Debt Component Grossed Up For Taxes (C)		16,607	16,542	16,477	16,412	16,347	16,281	16,216	16,151	16,086	16,021	15,956	15,890	194,986
8.	Investment Expenses														
	a. Depreciation (D)		47,647	47,647	47,647	47,647	47,647	47,647	47,647	47,647	47,647	47,647	47,647	47,647	571,764
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		126,993	126,682	126,371	126,060	125,748	125,436	125,125	124,814	124,503	124,191	123,880	123,568	1,503,371
	a. Recoverable Costs Allocated to Energy		126,993	126,682	126,371	126,060	125,748	125,436	125,125	124,814	124,503	124,191	123,880	123,568	1,503,371
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		126,993	126,682	126,371	126,060	125,748	125,436	125,125	124,814	124,503	124,191	123,880	123,568	1,503,371
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$126,993	$126,682	$126,371	$126,060	$125,748	$125,436	$125,125	$124,814	$124,503	$124,191	$123,880	$123,568	$1,503,371

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.45 ($21,855,886), 311.45 ($40,016), 316.40 ($71,401), 315.45 ($594,901), 312.42 ($1,637), and 312.40 ($90,088).
(B) Line 6 x 6.2009% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 2.5%, 2.0%, 4.2%, 3.1%, 3.7%, and 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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DOCKET NO. 20210007-EI
ECRC 2021 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT NO. MAS-2, DOCUMENT NO. 8,
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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Actual November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	
3.	Less: Accumulated Depreciation	1,505,355	1,495,171	1,484,987	1,474,803	1,464,619	1,454,435	1,444,251	1,434,067	1,423,883	1,413,699	1,403,515	1,393,331	1,383,147	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$4,696,207	$4,686,023	$4,675,839	$4,665,655	$4,655,471	$4,645,287	$4,635,103	$4,624,919	$4,614,735	$4,604,551	$4,594,367	$4,584,183	$4,573,999	
6.	Average Net Investment		4,691,115	4,680,931	4,670,747	4,660,563	4,650,379	4,640,195	4,630,011	4,619,827	4,609,643	4,599,459	4,589,275	4,579,091	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$24,241	$24,188	$24,136	$24,083	$24,030	$23,978	$23,925	$23,873	$23,820	$23,767	$23,715	$23,662	$287,418
	b. Debt Component Grossed Up For Taxes (C)		6,417	6,403	6,389	6,375	6,361	6,347	6,333	6,319	6,305	6,291	6,277	6,263	76,080
8.	Investment Expenses														
	a. Depreciation (D)		10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	122,208
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		40,842	40,775	40,709	40,642	40,575	40,509	40,442	40,376	40,309	40,242	40,176	40,109	485,706
	a. Recoverable Costs Allocated to Energy		40,842	40,775	40,709	40,642	40,575	40,509	40,442	40,376	40,309	40,242	40,176	40,109	485,706
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		40,842	40,775	40,709	40,642	40,575	40,509	40,442	40,376	40,309	40,242	40,176	40,109	485,706
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$40,842	$40,775	$40,709	$40,642	$40,575	$40,509	$40,442	$40,376	$40,309	$40,242	$40,176	$40,109	$485,706

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,675,171), 312.42 ($1,075,718), and 312.43 ($439,963).
(B) Line 6 x 6.2009% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 4.0%, 3.7%, and 3.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: PM Minimization and Monitoring
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	
3.	Less: Accumulated Depreciation	(7,275,250)	(7,336,122)	(7,396,994)	(7,457,866)	(7,518,738)	(7,579,610)	(7,640,482)	(7,701,354)	(7,762,226)	(7,823,098)	(7,883,970)	(7,944,842)	(8,005,714)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$12,482,500	$12,421,628	$12,360,756	$12,299,884	$12,239,012	$12,178,140	$12,117,268	$12,056,396	$11,995,524	$11,934,652	$11,873,780	$11,812,908	$11,752,036	
6.	Average Net Investment		12,452,064	12,391,192	12,330,320	12,269,448	12,208,576	12,147,704	12,086,832	12,025,960	11,965,088	11,904,216	11,843,344	11,782,472	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$64,345	$64,030	$63,716	$63,401	$63,087	$62,772	$62,458	$62,143	$61,829	$61,514	$61,199	$60,885	$751,379
	b. Debt Component Grossed Up For Taxes (C)		17,032	16,949	16,866	16,783	16,699	16,616	16,533	16,450	16,366	16,283	16,200	16,116	198,893
8.	Investment Expenses														
	a. Depreciation (D)		60,872	60,872	60,872	60,872	60,872	60,872	60,872	60,872	60,872	60,872	60,872	60,872	730,464
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		142,249	141,851	141,454	141,056	140,658	140,260	139,863	139,465	139,067	138,669	138,271	137,873	1,680,736
	a. Recoverable Costs Allocated to Energy		142,249	141,851	141,454	141,056	140,658	140,260	139,863	139,465	139,067	138,669	138,271	137,873	1,680,736
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		142,249	141,851	141,454	141,056	140,658	140,260	139,863	139,465	139,067	138,669	138,271	137,873	1,680,736
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$142,249	$141,851	$141,454	$141,056	$140,658	$140,260	$139,863	$139,465	$139,067	$138,669	$138,271	$137,873	$1,680,736

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($5,831,465), 312.42 ($5,153,072), 312.43 ($7,875,560), 315.41 ($17,504), 315.44 ($351,594), and 315.43 ($528,554).
(B) Line 6 x 6.2009% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 4.0%, 3.7%, 3.5%, 3.5%, 3.2%, and 3.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Polk NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	
3.	Less: Accumulated Depreciation	(895,674)	(900,098)	(904,522)	(908,946)	(913,370)	(917,794)	(922,218)	(926,642)	(931,066)	(935,490)	(939,914)	(944,338)	(948,762)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$665,799	$661,375	$656,951	$652,527	$648,103	$643,679	$639,255	$634,831	$630,407	$625,983	$621,559	$617,135	$612,711	
6.	Average Net Investment		663,587	659,163	654,739	650,315	645,891	641,467	637,043	632,619	628,195	623,771	619,347	614,923	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$3,429	$3,406	$3,383	$3,360	$3,338	$3,315	$3,292	$3,269	$3,246	$3,223	$3,200	$3,178	$39,639
	b. Debt Component Grossed Up For Taxes (C)		908	902	896	890	883	877	871	865	859	853	847	841	10,492
8.	Investment Expenses														
	a. Depreciation (D)		4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	53,088
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		8,761	8,732	8,703	8,674	8,645	8,616	8,587	8,558	8,529	8,500	8,471	8,443	103,219
	a. Recoverable Costs Allocated to Energy		8,761	8,732	8,703	8,674	8,645	8,616	8,587	8,558	8,529	8,500	8,471	8,443	103,219
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		8,761	8,732	8,703	8,674	8,645	8,616	8,587	8,558	8,529	8,500	8,471	8,443	103,219
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$8,761	$8,732	$8,703	$8,674	$8,645	$8,616	$8,587	$8,558	$8,529	$8,500	$8,471	$8,443	$103,219

Notes:

(A) Applicable depreciable base for Polk; account 342.81
(B) Line 6 x 6.2009% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SOFA
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	
3.	Less: Accumulated Depreciation	(1,139,726)	(1,146,123)	(1,152,520)	(1,158,917)	(1,165,314)	(1,171,711)	(1,178,108)	(1,184,505)	(1,190,902)	(1,197,299)	(1,203,696)	(1,210,093)	(1,216,490)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,419,004	$1,412,607	$1,406,210	$1,399,813	$1,393,416	$1,387,019	$1,380,622	$1,374,225	$1,367,828	$1,361,431	$1,355,034	$1,348,637	$1,342,240	
6.	Average Net Investment		1,415,806	1,409,409	1,403,012	1,396,615	1,390,218	1,383,821	1,377,424	1,371,027	1,364,630	1,358,233	1,351,836	1,345,439	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$7,316	$7,283	$7,250	$7,217	$7,184	$7,151	$7,118	$7,085	$7,052	$7,019	$6,985	$6,952	$85,612
	b. Debt Component Grossed Up For Taxes (C)		1,937	1,928	1,919	1,910	1,902	1,893	1,884	1,875	1,867	1,858	1,849	1,840	22,662
8.	Investment Expenses														
	a. Depreciation (D)		6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	76,764
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		15,650	15,608	15,566	15,524	15,483	15,441	15,399	15,357	15,316	15,274	15,231	15,189	185,038
	a. Recoverable Costs Allocated to Energy		15,650	15,608	15,566	15,524	15,483	15,441	15,399	15,357	15,316	15,274	15,231	15,189	185,038
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		15,650	15,608	15,566	15,524	15,483	15,441	15,399	15,357	15,316	15,274	15,231	15,189	185,038
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$15,650	$15,608	$15,566	$15,524	$15,483	$15,441	$15,399	$15,357	$15,316	$15,274	$15,231	$15,189	$185,038

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44
(B) Line 6 x 6.2009% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	
3.	Less: Accumulated Depreciation	(863,521)	(869,018)	(874,515)	(880,012)	(885,509)	(891,006)	(896,503)	(902,000)	(907,497)	(912,994)	(918,491)	(923,988)	(929,485)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$785,600	$780,103	$774,606	$769,109	$763,612	$758,115	$752,618	$747,121	$741,624	$736,127	$730,630	$725,133	$719,636	
6.	Average Net Investment		782,852	777,355	771,858	766,361	760,864	755,367	749,870	744,373	738,876	733,379	727,882	722,385	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$4,045	$4,017	$3,989	$3,960	$3,932	$3,903	$3,875	$3,846	$3,818	$3,790	$3,761	$3,733	$46,669
	b. Debt Component Grossed Up For Taxes (C)		1,071	1,063	1,056	1,048	1,041	1,033	1,026	1,018	1,011	1,003	996	988	12,354
8.	Investment Expenses														
	a. Depreciation (D)		5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	65,964
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		10,613	10,577	10,542	10,505	10,470	10,433	10,398	10,361	10,326	10,290	10,254	10,218	124,987
	a. Recoverable Costs Allocated to Energy		10,613	10,577	10,542	10,505	10,470	10,433	10,398	10,361	10,326	10,290	10,254	10,218	124,987
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		10,613	10,577	10,542	10,505	10,470	10,433	10,398	10,361	10,326	10,290	10,254	10,218	124,987
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$10,613	$10,577	$10,542	$10,505	$10,470	$10,433	$10,398	$10,361	$10,326	$10,290	$10,254	$10,218	$124,987

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 6.2009% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 4.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	
3.	Less: Accumulated Depreciation	(769,892)	(774,769)	(779,646)	(784,523)	(789,400)	(794,277)	(799,154)	(804,031)	(808,908)	(813,785)	(818,662)	(823,539)	(828,416)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$811,995	$807,118	$802,241	$797,364	$792,487	$787,610	$782,733	$777,856	$772,979	$768,102	$763,225	$758,348	$753,471	
6.	Average Net Investment		809,557	804,680	799,803	794,926	790,049	785,172	780,295	775,418	770,541	765,664	760,787	755,910	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$4,183	$4,158	$4,133	$4,108	$4,083	$4,057	$4,032	$4,007	$3,982	$3,957	$3,931	$3,906	$48,537
	b. Debt Component Grossed Up For Taxes (C)		1,107	1,101	1,094	1,087	1,081	1,074	1,067	1,061	1,054	1,047	1,041	1,034	12,848
8.	Investment Expenses														
	a. Depreciation (D)		4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	58,524
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		10,167	10,136	10,104	10,072	10,041	10,008	9,976	9,945	9,913	9,881	9,849	9,817	119,909
	a. Recoverable Costs Allocated to Energy		10,167	10,136	10,104	10,072	10,041	10,008	9,976	9,945	9,913	9,881	9,849	9,817	119,909
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		10,167	10,136	10,104	10,072	10,041	10,008	9,976	9,945	9,913	9,881	9,849	9,817	119,909
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$10,167	$10,136	$10,104	$10,072	$10,041	$10,008	$9,976	$9,945	$9,913	$9,881	$9,849	$9,817	$119,909

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 6.2009% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Form 42-8E

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	
3.	Less: Accumulated Depreciation	(1,118,510)	(1,126,463)	(1,134,416)	(1,142,369)	(1,150,322)	(1,158,275)	(1,166,228)	(1,174,181)	(1,182,134)	(1,190,087)	(1,198,040)	(1,205,993)	(1,213,946)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,587,997	$1,580,044	$1,572,091	$1,564,138	$1,556,185	$1,548,232	$1,540,279	$1,532,326	$1,524,373	$1,516,420	$1,508,467	$1,500,514	$1,492,561	
6.	Average Net Investment		1,584,021	1,576,068	1,568,115	1,560,162	1,552,209	1,544,256	1,536,303	1,528,350	1,520,397	1,512,444	1,504,491	1,496,538	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$8,185	$8,144	$8,103	$8,062	$8,021	$7,980	$7,939	$7,898	$7,857	$7,815	$7,774	$7,733	$95,511
	b. Debt Component Grossed Up For Taxes (C)		2,167	2,156	2,145	2,134	2,123	2,112	2,101	2,091	2,080	2,069	2,058	2,047	25,283
8.	Investment Expenses														
	a. Depreciation (D)		7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	95,436
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		18,305	18,253	18,201	18,149	18,097	18,045	17,993	17,942	17,890	17,837	17,785	17,733	216,230
	a. Recoverable Costs Allocated to Energy		18,305	18,253	18,201	18,149	18,097	18,045	17,993	17,942	17,890	17,837	17,785	17,733	216,230
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		18,305	18,253	18,201	18,149	18,097	18,045	17,993	17,942	17,890	17,837	17,785	17,733	216,230
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$18,305	$18,253	$18,201	$18,149	$18,097	$18,045	$17,993	$17,942	$17,890	$17,837	$17,785	$17,733	$216,230

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.43 ($1,995,677) and 315.43 ($710,830).
(B) Line 6 x 6.2009% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 3.5% and 3.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	
3.	Less: Accumulated Depreciation	(39,979,614)	(40,288,780)	(40,597,946)	(40,907,112)	(41,216,278)	(41,525,444)	(41,834,610)	(42,143,776)	(42,452,942)	(42,762,108)	(43,071,274)	(43,380,440)	(43,689,606)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$45,739,488	$45,430,322	$45,121,156	$44,811,990	$44,502,824	$44,193,658	$43,884,492	$43,575,326	$43,266,160	$42,956,994	$42,647,828	$42,338,662	$42,029,496	
6.	Average Net Investment		45,584,905	45,275,739	44,966,573	44,657,407	44,348,241	44,039,075	43,729,909	43,420,743	43,111,577	42,802,411	42,493,245	42,184,079	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$235,556	$233,959	$232,361	$230,763	$229,166	$227,568	$225,971	$224,373	$222,775	$221,178	$219,580	$217,983	$2,721,233
	b. Debt Component Grossed Up For Taxes (C)		62,353	61,930	61,507	61,084	60,661	60,238	59,815	59,392	58,969	58,547	58,124	57,701	720,321
8.	Investment Expenses														
	a. Depreciation (D)		309,166	309,166	309,166	309,166	309,166	309,166	309,166	309,166	309,166	309,166	309,166	309,166	3,709,992
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		607,075	605,055	603,034	601,013	598,993	596,972	594,952	592,931	590,910	588,891	586,870	584,850	7,151,546
	a. Recoverable Costs Allocated to Energy		607,075	605,055	603,034	601,013	598,993	596,972	594,952	592,931	590,910	588,891	586,870	584,850	7,151,546
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		607,075	605,055	603,034	601,013	598,993	596,972	594,952	592,931	590,910	588,891	586,870	584,850	7,151,546
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$607,075	$605,055	$603,034	$601,013	$598,993	$596,972	$594,952	$592,931	$590,910	$588,891	$586,870	$584,850	$7,151,546

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.51 ($22,278,982), 312.51 ($48,529,672), 315.51 ($14,063,245), and 316.51 ($847,203).
(B) Line 6 x 6.2009% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 4.1%, 4.3%, 4.8%, and 4.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	
3.	Less: Accumulated Depreciation	(42,023,760)	(42,336,137)	(42,648,514)	(42,960,891)	(43,273,268)	(43,585,645)	(43,898,022)	(44,210,399)	(44,522,776)	(44,835,153)	(45,147,530)	(45,459,907)	(45,772,284)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$54,514,373	$54,201,996	$53,889,619	$53,577,242	$53,264,865	$52,952,488	$52,640,111	$52,327,734	$52,015,357	$51,702,980	$51,390,603	$51,078,226	$50,765,849	
6.	Average Net Investment		54,358,184	54,045,807	53,733,430	53,421,053	53,108,676	52,796,299	52,483,922	52,171,545	51,859,168	51,546,791	51,234,414	50,922,037	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$280,891	$279,277	$277,663	$276,049	$274,435	$272,820	$271,206	$269,592	$267,978	$266,364	$264,750	$263,135	$3,264,160
	b. Debt Component Grossed Up For Taxes (C)		74,353	73,926	73,498	73,071	72,644	72,217	71,789	71,362	70,935	70,507	70,080	69,653	864,035
8.	Investment Expenses														
	a. Depreciation (D)		312,377	312,377	312,377	312,377	312,377	312,377	312,377	312,377	312,377	312,377	312,377	312,377	3,748,524
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		667,621	665,580	663,538	661,497	659,456	657,414	655,372	653,331	651,290	649,248	647,207	645,165	7,876,719
	a. Recoverable Costs Allocated to Energy		667,621	665,580	663,538	661,497	659,456	657,414	655,372	653,331	651,290	649,248	647,207	645,165	7,876,719
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		667,621	665,580	663,538	661,497	659,456	657,414	655,372	653,331	651,290	649,248	647,207	645,165	7,876,719
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$667,621	$665,580	$663,538	$661,497	$659,456	$657,414	$655,372	$653,331	$651,290	$649,248	$647,207	$645,165	$7,876,719

Notes:
(A) Applicable depreciable base for Big Bend; account 311.52 ($25,208,869), 312.52 ($54,456,221), 315.52 ($15,914,427), and 316.52 ($958,616).
(B) Line 6 x 6.2009% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rates are 3.5%, 4.0%, 4.1% and 3.7%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	
3.	Less: Accumulated Depreciation	(37,013,361)	(37,265,435)	(37,517,509)	(37,769,583)	(38,021,657)	(38,273,731)	(38,525,805)	(38,777,879)	(39,029,953)	(39,282,027)	(39,534,101)	(39,786,175)	(40,038,249)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$44,751,241	$44,499,167	$44,247,093	$43,995,019	$43,742,945	$43,490,871	$43,238,797	$42,986,723	$42,734,649	$42,482,575	$42,230,501	$41,978,427	$41,726,353	
6.	Average Net Investment		44,625,204	44,373,130	44,121,056	43,868,982	43,616,908	43,364,834	43,112,760	42,860,686	42,608,612	42,356,538	42,104,464	41,852,390	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$230,597	$229,294	$227,992	$226,689	$225,387	$224,084	$222,782	$221,479	$220,176	$218,874	$217,571	$216,269	$2,681,194
	b. Debt Component Grossed Up For Taxes (C)		61,040	60,695	60,350	60,005	59,661	59,316	58,971	58,626	58,281	57,937	57,592	57,247	709,721
8.	Investment Expenses														
	a. Depreciation (D)		252,074	252,074	252,074	252,074	252,074	252,074	252,074	252,074	252,074	252,074	252,074	252,074	3,024,888
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		543,711	542,063	540,416	538,768	537,122	535,474	533,827	532,179	530,531	528,885	527,237	525,590	6,415,803
	a. Recoverable Costs Allocated to Energy		543,711	542,063	540,416	538,768	537,122	535,474	533,827	532,179	530,531	528,885	527,237	525,590	6,415,803
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		543,711	542,063	540,416	538,768	537,122	535,474	533,827	532,179	530,531	528,885	527,237	525,590	6,415,803
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$543,711	$542,063	$540,416	$538,768	$537,122	$535,474	$533,827	$532,179	$530,531	$528,885	$527,237	$525,590	$6,415,803

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.53 ($21,689,422), 312.53 ($45,559,543), 315.53 ($13,690,954), and 316.53 ($824,684).
(B) Line 6 x 6.2009% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 3.1%, 3.9%, 4.0%, and 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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DOCKET NO. 20210007-EI
ECRC 2021 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT NO. MAS-2, DOCUMENT NO. 8,
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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$1,428	$4,801	$6,274	$14,610	$19,438	$311,569	$261,768	$102,049	$52,035	$773,972
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	773,972	773,972
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$67,588,833	
3.	Less: Accumulated Depreciation	(29,385,303)	(29,577,771)	(29,770,239)	(29,962,707)	(30,155,175)	(30,347,643)	(30,540,111)	(30,732,579)	(30,925,047)	(31,117,515)	(31,309,983)	(31,502,451)	(31,694,919)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	1,428	6,229	12,503	27,113	46,551	358,120	619,888	721,937	0	
5.	Net Investment (Lines 2 + 3 + 4)	$37,429,558	$37,237,090	$37,044,622	$36,852,154	$36,661,114	$36,473,447	$36,287,253	$36,109,395	$35,936,365	$36,055,466	$36,124,766	$36,034,347	$35,893,914	
6.	Average Net Investment		37,333,324	37,140,856	36,948,388	36,756,634	36,567,280	36,380,350	36,198,324	36,022,880	35,995,915	36,090,116	36,079,556	35,964,130	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$192,917	$191,922	$190,928	$189,937	$188,958	$187,992	$187,052	$186,145	$186,006	$186,493	$186,438	$185,842	$2,260,630
	b. Debt Component Grossed Up For Taxes (C)		51,066	50,803	50,539	50,277	50,018	49,762	49,513	49,273	49,236	49,365	49,351	49,193	598,396
8.	Investment Expenses														
	a. Depreciation (D)		192,468	192,468	192,468	192,468	192,468	192,468	192,468	192,468	192,468	192,468	192,468	192,468	2,309,616
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		436,451	435,193	433,935	432,682	431,444	430,222	429,033	427,886	427,710	428,326	428,257	427,503	5,168,642
	a. Recoverable Costs Allocated to Energy		436,451	435,193	433,935	432,682	431,444	430,222	429,033	427,886	427,710	428,326	428,257	427,503	5,168,642
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		436,451	435,193	433,935	432,682	431,444	430,222	429,033	427,886	427,710	428,326	428,257	427,503	5,168,642
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$436,451	$435,193	$433,935	$432,682	$431,444	$430,222	$429,033	$427,886	$427,710	$428,326	$428,257	$427,503	$5,168,642

Notes:

(A) Applicable depreciable base for Big Bend; accounts 311.54 ($16,857,250), 312.54 ($38,069,546), 315.54 ($10,642,027), 316.54 ($687,934), 315.40 ($558,103), and 312.44 ($773,972).
(B) Line 6 x 6.2009% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 2.4%, 3.8%, 3.9%, 3.3%, 3.7%, and 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD System Reliability
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	
3.	Less: Accumulated Depreciation	(6,453,865)	(6,505,447)	(6,557,029)	(6,608,611)	(6,660,193)	(6,711,775)	(6,763,357)	(6,814,939)	(6,866,521)	(6,918,103)	(6,969,685)	(7,021,267)	(7,072,849)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$18,013,941	$17,962,359	$17,910,777	$17,859,195	$17,807,613	$17,756,031	$17,704,449	$17,652,867	$17,601,285	$17,549,703	$17,498,121	$17,446,539	$17,394,957	
6.	Average Net Investment		17,988,150	17,936,568	17,884,986	17,833,404	17,781,822	17,730,240	17,678,658	17,627,076	17,575,494	17,523,912	17,472,330	17,420,748	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$92,952	$92,686	$92,419	$92,153	$91,886	$91,620	$91,353	$91,086	$90,820	$90,553	$90,287	$90,020	$1,097,835
	b. Debt Component Grossed Up For Taxes (C)		24,605	24,534	24,464	24,393	24,323	24,252	24,181	24,111	24,040	23,970	23,899	23,829	290,601
8.	Investment Expenses														
	a. Depreciation (D)		51,582	51,582	51,582	51,582	51,582	51,582	51,582	51,582	51,582	51,582	51,582	51,582	618,984
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		169,139	168,802	168,465	168,128	167,791	167,454	167,116	166,779	166,442	166,105	165,768	165,431	2,007,420
	a. Recoverable Costs Allocated to Energy		169,139	168,802	168,465	168,128	167,791	167,454	167,116	166,779	166,442	166,105	165,768	165,431	2,007,420
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		169,139	168,802	168,465	168,128	167,791	167,454	167,116	166,779	166,442	166,105	165,768	165,431	2,007,420
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$169,139	$168,802	$168,465	$168,128	$167,791	$167,454	$167,116	$166,779	$166,442	$166,105	$165,768	$165,431	$2,007,420

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.45 ($23,011,597) and 312.44 ($1,456,209).
(B) Line 6 x 6.2009% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 2.5% and 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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DOCKET NO. 20210007-EI
ECRC 2021 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT NO. MAS-2, DOCUMENT NO. 8,
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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Mercury Air Toxics Standards (MATS)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	13,614	0	0	0	0	0	13,614
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$8,621,413	$8,621,413	$8,621,413	$8,621,413	$8,621,413	$8,621,413	$8,621,413	$8,635,028	$8,635,028	$8,635,028	$8,635,028	$8,635,028	$8,635,028	
3.	Less: Accumulated Depreciation	(1,955,259)	(1,977,555)	(1,999,851)	(2,022,147)	(2,044,443)	(2,066,739)	(2,089,035)	(2,111,331)	(2,133,666)	(2,156,001)	(2,178,336)	(2,200,671)	(2,223,006)	
4.	CWIP - Non-Interest Bearing	13,614	13,614	13,614	13,614	13,614	13,614	13,614	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$6,679,769	$6,657,473	$6,635,177	$6,612,881	$6,590,585	$6,568,289	$6,545,993	$6,523,697	$6,501,362	$6,479,027	$6,456,692	$6,434,357	$6,412,022	
6.	Average Net Investment		6,668,621	6,646,325	6,624,029	6,601,733	6,579,437	6,557,141	6,534,845	6,512,529	6,490,194	6,467,859	6,445,524	6,423,189	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$34,460	$34,344	$34,229	$34,114	$33,999	$33,883	$33,768	$33,653	$33,538	$33,422	$33,307	$33,191	$405,908
	b. Debt Component Grossed Up For Taxes (C)		9,122	9,091	9,061	9,030	9,000	8,969	8,939	8,908	8,878	8,847	8,816	8,786	107,447
8.	Investment Expenses														
	a. Depreciation (D)		22,296	22,296	22,296	22,296	22,296	22,296	22,296	22,335	22,335	22,335	22,335	22,335	267,747
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		65,878	65,731	65,586	65,440	65,295	65,148	65,003	64,896	64,751	64,604	64,458	64,312	781,102
	a. Recoverable Costs Allocated to Energy		65,878	65,731	65,586	65,440	65,295	65,148	65,003	64,896	64,751	64,604	64,458	64,312	781,102
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		65,878	65,731	65,586	65,440	65,295	65,148	65,003	64,896	64,751	64,604	64,458	64,312	781,102
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$65,878	$65,731	$65,586	$65,440	$65,295	$65,148	$65,003	$64,896	$64,751	$64,604	$64,458	$64,312	$781,102

Notes:
(A) Applicable depreciable base for Big Bend and Polk; accounts 312.44 ($3,427,481), 341.80 ($26,150), 315.40 ($1,226,949), 315.41 ($138,853), 315.42 ($138,853), 312.45 ($2,053,017), 312.46 ($1,242,315), 315.44 ($16,035), 315.45 ($40,217), 315.46 ($50,784), 311.40 ($13,216), 345.81 ($2,232), 312.54 ($210,295), 312.40 ($13,614), and 395.00 ($35,018).
(B) Line 6 x 6.2009% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 3.0%, 2.2%, 3.7%, 3.5%, 3.3%, 2.5%, 3.3%, 3.2%, 3.1%, 3.5%, 2.9%, 3.3%, 3.8%, 3.4%, and 14.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

For Project: SO_2 Emissions Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Purchases/Transfers		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Working Capital Balance														
	a. FERC 158.1 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
	b. FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c. FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d. FERC 254.01 Regulatory Liabilities - Gains	(34,249)	(34,238)	(34,238)	(34,238)	(34,225)	(34,225)	(34,225)	(34,213)	(34,213)	(34,213)	(34,201)	(34,201)	(34,201)	
3.	Total Working Capital Balance	($34,249)	($34,238)	($34,238)	($34,238)	($34,225)	($34,225)	($34,225)	($34,213)	($34,213)	($34,213)	($34,201)	($34,201)	($34,201)	
4.	Average Net Working Capital Balance		($34,244)	($34,238)	($34,238)	($34,232)	($34,225)	($34,225)	($34,219)	($34,213)	($34,213)	($34,207)	($34,201)	($34,201)	
5.	Return on Average Net Working Capital Balance														
	a. Equity Component Grossed Up For Taxes (A)		($177)	($177)	($177)	($177)	($177)	($177)	($177)	($177)	($177)	($177)	($177)	($177)	(2,124)
	b. Debt Component Grossed Up For Taxes (B)		(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(564)
6.	Total Return Component		(224)	(224)	(224)	(224)	(224)	(224)	(224)	(224)	(224)	(224)	(224)	(224)	(2,688)
7.	Expenses:		1	2	3	4	5	6	7	8	9	10	11	12	
	a. Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. SO_2 Allowance Expense		(6)	11	9	(11)	5	14	(5)	7	7	(5)	7	7	41
8.	Net Expenses (D)		(6)	11	9	(11)	5	14	(5)	7	7	(5)	7	7	41
9.	Total System Recoverable Expenses (Lines 6 + 8)		(230)	(213)	(215)	(235)	(219)	(210)	(229)	(217)	(217)	(229)	(217)	(217)	(2,647)
	a. Recoverable Costs Allocated to Energy		(230)	(213)	(215)	(235)	(219)	(210)	(229)	(217)	(217)	(229)	(217)	(217)	(2,647)
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		(230)	(213)	(215)	(235)	(219)	(210)	(229)	(217)	(217)	(229)	(217)	(217)	(2,648)
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Juris. Recoverable Costs (Lines 12 + 13)		($230)	($213)	($215)	($235)	($219)	($210)	($229)	($217)	($217)	($229)	($217)	($217)	($2,648)

Notes:
(A) Line 6 x 6.2009% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(B) Line 6 x 1.6414% x 1/12
(C) Line 6 is reported on Schedule 7E.
(D) Line 8 is reported on Schedule 5E.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Gypsum Storage Facility
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	
3.	Less: Accumulated Depreciation	(3,777,423)	(3,829,302)	(3,881,181)	(3,933,060)	(3,984,939)	(4,036,818)	(4,088,697)	(4,140,576)	(4,192,455)	(4,244,334)	(4,296,213)	(4,348,092)	(4,399,971)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$17,689,936	$17,638,057	$17,586,178	$17,534,299	$17,482,420	$17,430,541	$17,378,662	$17,326,783	$17,274,904	$17,223,025	$17,171,146	$17,119,267	$17,067,388	
6.	Average Net Investment		17,663,997	17,612,118	17,560,239	17,508,360	17,456,481	17,404,602	17,352,723	17,300,844	17,248,965	17,197,086	17,145,207	17,093,328	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$91,277	$91,009	$90,741	$90,473	$90,205	$89,937	$89,669	$89,401	$89,133	$88,865	$88,596	$88,328	$1,077,634
	b. Debt Component Grossed Up For Taxes (C)		24,161	24,090	24,019	23,949	23,878	23,807	23,736	23,665	23,594	23,523	23,452	23,381	285,255
8.	Investment Expenses														
	a. Depreciation (D)		51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	622,548
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		167,317	166,978	166,639	166,301	165,962	165,623	165,284	164,945	164,606	164,267	163,927	163,588	1,985,437
	a. Recoverable Costs Allocated to Energy		167,317	166,978	166,639	166,301	165,962	165,623	165,284	164,945	164,606	164,267	163,927	163,588	1,985,437
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		167,317	166,978	166,639	166,301	165,962	165,623	165,284	164,945	164,606	164,267	163,927	163,588	1,985,437
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$167,317	$166,978	$166,639	$166,301	$165,962	$165,623	$165,284	$164,945	$164,606	$164,267	$163,927	$163,588	$1,985,437

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.40
(B) Line 6 x 6.2009% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 2.9%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Coal Combustion Residual Rule (CCR Rule)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$797,231	$159,684	$213,313	$1,975	$30,092	$21,491	$93,819	$0	$0	$0	$0	$0	$1,317,604
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	2,178,467	0	794,761	2,973,228
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$930,303	$930,303	$930,303	$930,303	$930,303	$930,303	$930,303	$930,303	$930,303	$930,303	$3,108,770	$3,108,770	$3,903,531	
3.	Less: Accumulated Depreciation	(77,769)	(80,073)	(82,377)	(84,681)	(86,985)	(89,289)	(91,593)	(93,897)	(96,201)	(98,505)	(100,809)	(109,285)	(117,761)	
4.	CWIP - Non-Interest Bearing	1,655,624	2,452,855	2,612,539	2,825,852	2,827,827	2,857,919	2,879,409	2,973,228	2,973,228	2,973,228	794,761	794,761	0	
5.	Net Investment (Lines 2 + 3 + 4)	$2,508,158	$3,303,085	$3,460,465	$3,671,474	$3,671,145	$3,698,933	$3,718,119	$3,809,634	$3,807,330	$3,805,026	$3,802,722	$3,794,246	$3,785,770	
6.	Average Net Investment		2,905,622	3,381,775	3,565,970	3,671,309	3,685,039	3,708,526	3,763,877	3,808,482	3,806,178	3,803,874	3,798,484	3,790,008	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$15,015	$17,475	$18,427	$18,971	$19,042	$19,163	$19,450	$19,680	$19,668	$19,656	$19,628	$19,585	$225,760
	b. Debt Component Grossed Up For Taxes (C)		3,974	4,626	4,878	5,022	5,041	5,073	5,148	5,209	5,206	5,203	5,196	5,184	59,760
8.	Investment Expenses														
	a. Depreciation (D)		2,304	2,304	2,304	2,304	2,304	2,304	2,304	2,304	2,304	2,304	8,476	8,476	39,992
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		21,293	24,405	25,609	26,297	26,387	26,540	26,902	27,193	27,178	27,163	33,300	33,245	325,512
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		21,293	24,405	25,609	26,297	26,387	26,540	26,902	27,193	27,178	27,163	33,300	33,245	325,512
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		21,293	24,405	25,609	26,297	26,387	26,540	26,902	27,193	27,178	27,163	33,300	33,245	325,512
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$21,293	$24,405	$25,609	$26,297	$26,387	$26,540	$26,902	$27,193	$27,178	$27,163	$33,300	$33,245	$325,512

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.40 ($261,568), 312.44 ($668,735) and 312.40 ($2,973,228).
(B) Line 6 x 6.2009% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 2.9%, 3.0% and 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Coal Combustion Residuals (CCR Rule - Phase II)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$14,692	$36,627	$4,051	$4,190	$7,631	$7,380	$258,399	$264,350	$255,950	$0	$0	($0)	$853,269
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	2,009,031	0	(0)	2,009,031
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,009,031	$2,009,031	$2,009,031	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	(5,023)	(10,046)	
4.	CWIP - Non-Interest Bearing	1,155,762	1,170,454	1,207,080	1,211,131	1,215,321	1,222,952	1,230,332	1,488,731	1,753,081	2,009,031	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,155,762	$1,170,454	$1,207,080	$1,211,131	$1,215,321	$1,222,952	$1,230,332	$1,488,731	$1,753,081	$2,009,031	$2,009,031	$2,004,008	$1,998,985	
6.	Average Net Investment		1,163,108	1,188,767	1,209,106	1,213,226	1,219,137	1,226,642	1,359,532	1,620,906	1,881,056	2,009,031	2,006,520	2,001,497	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$6,010	$6,143	$6,248	$6,269	$6,300	$6,339	$7,025	$8,376	$9,720	$10,382	$10,369	$10,343	$93,524
	b. Debt Component Grossed Up For Taxes (C)		1,591	1,626	1,654	1,659	1,668	1,678	1,860	2,217	2,573	2,748	2,745	2,738	24,757
8.	Investment Expenses														
	a. Depreciation (D)		0	0	0	0	0	0	0	0	0	0	5,023	5,023	10,046
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		7,601	7,769	7,902	7,928	7,968	8,017	8,885	10,593	12,293	13,130	18,137	18,104	128,327
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		7,601	7,769	7,902	7,928	7,968	8,017	8,885	10,593	12,293	13,130	18,137	18,104	128,327
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		7,601	7,769	7,902	7,928	7,968	8,017	8,885	10,593	12,293	13,130	18,137	18,104	128,327
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$7,601	$7,769	$7,902	$7,928	$7,968	$8,017	$8,885	$10,593	$12,293	$13,130	$18,137	$18,104	$128,327

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.44.
(B) Line 6 x 6.2009% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate 3.0%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend ELG Compliance
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$136,645	$141,845	$267,978	$8,948	$417,361	$607,383	$1,185,199	$660,199	$1,105,199	$3,107,983	$1,590,199	$1,480,199	$10,709,141
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	2,522,506	2,659,151	2,800,997	3,068,975	3,077,923	3,495,285	4,102,668	5,287,867	5,948,066	7,053,265	10,161,248	11,751,447	13,231,646	
5.	Net Investment (Lines 2 + 3 + 4)	$2,522,506	$2,659,151	$2,800,997	$3,068,975	$3,077,923	$3,495,285	$4,102,668	$5,287,867	$5,948,066	$7,053,265	$10,161,248	$11,751,447	$13,231,646	
6.	Average Net Investment		2,590,828	2,730,074	2,934,986	3,073,449	3,286,604	3,798,976	4,695,267	5,617,966	6,500,666	8,607,257	10,956,347	12,491,547	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$13,388	$14,107	$15,166	$15,882	$16,983	$19,631	$24,262	$29,030	$33,592	$44,477	$56,616	$64,549	$347,683
	b. Debt Component Grossed Up For Taxes (C)		3,544	3,734	4,015	4,204	4,496	5,196	6,422	7,684	8,892	11,773	14,986	17,086	92,032
8.	Investment Expenses														
	a. Depreciation (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		16,932	17,841	19,181	20,086	21,479	24,827	30,684	36,714	42,484	56,250	71,602	81,635	439,715
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		16,932	17,841	19,181	20,086	21,479	24,827	30,684	36,714	42,484	56,250	71,602	81,635	439,715
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		16,932	17,841	19,181	20,086	21,479	24,827	30,684	36,714	42,484	56,250	71,602	81,635	439,715
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$16,932	$17,841	$19,181	$20,086	$21,479	$24,827	$30,684	$36,714	$42,484	$56,250	$71,602	$81,635	$439,715

Notes:
(A) Applicable depreciable base for Big Bend; accounts TBD depending on type of plant added
(B) Line 6 x 6.2009% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is TBD depending on type of plant added
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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ECRC 2021 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT NO. MAS-2, DOCUMENT NO. 8,
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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Section 316(b) Impingement Mortality
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$468,674	$278,711	$1,919,704	$297,640	$311,598	$951,231	$873,244	$1,030,395	$2,044,496	$2,097,870	$1,065,476	$459,856	$11,798,893
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	1,072,932	1,541,605	1,820,317	3,740,021	4,037,660	4,349,259	5,300,489	6,173,733	7,204,128	9,248,624	11,346,494	12,411,969	12,871,825	
5.	Net Investment (Lines 2 + 3 + 4)	$1,072,932	$1,541,605	$1,820,317	$3,740,021	$4,037,660	$4,349,259	$5,300,489	$6,173,733	$7,204,128	$9,248,624	$11,346,494	$12,411,969	$12,871,825	
6.	Average Net Investment		1,307,269	1,680,961	2,780,169	3,888,841	4,193,459	4,824,874	5,737,111	6,688,931	8,226,376	10,297,559	11,879,231	12,641,897	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$6,755	$8,686	$14,366	$20,095	$21,669	$24,932	$29,646	$34,564	$42,509	$53,212	$61,385	$65,326	$383,145
	b. Debt Component Grossed Up For Taxes (C)		1,788	2,299	3,803	5,319	5,736	6,600	7,847	9,149	11,252	14,085	16,249	17,292	101,419
8.	Investment Expenses														
	a. Depreciation (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		8,543	10,985	18,169	25,414	27,405	31,532	37,493	43,713	53,761	67,297	77,634	82,618	484,564
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		8,543	10,985	18,169	25,414	27,405	31,532	37,493	43,713	53,761	67,297	77,634	82,618	484,564
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		8,543	10,985	18,169	25,414	27,405	31,532	37,493	43,713	53,761	67,297	77,634	82,618	484,564
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$8,543	$10,985	$18,169	$25,414	$27,405	$31,532	$37,493	$43,713	$53,761	$67,297	$77,634	$82,618	$484,564

Notes:
(A) Applicable depreciable base for Big Bend; accounts TBD depending on type of plant added
(B) Line 6 x 6.2009% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is TBD depending on type of plant added
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Form 42 - 9E

Calculation of Revenue Requirement Rate of Return
(in Dollars)

	(1) Jurisdictional Rate Base **2021 Adj. FESR** ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 2,398,774	33.85%	4.34%	1.4692%
Short Term Debt	299,519	4.23%	1.06%	0.0448%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	86,301	1.22%	2.44%	0.0297%
Common Equity	3,147,963	44.43%	10.25%	4.5537%
Accum. Deferred Inc. Taxes & Zero Cost ITC's	948,501	13.39%	0.00%	0.0000%
Deferred ITC - Weighted Cost	204,707	2.89%	7.35%	0.2123%
Total	$ 7,085,765	100.00%		6.31%

ITC split between Debt and Equity:

Long Term Debt	$ 2,398,774	Long Term Debt	46.00%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	3,147,963	Equity - Common	54.00%
Total	$ 5,546,737	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = 0.2123% * 46.00%	0.0977%
Equity = 0.2123% * 54.00%	0.1146%
Weighted Cost	0.2123%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.5537%
Deferred ITC - Weighted Cost	0.1146%
	4.6683%
Times Tax Multiplier	1.32830
Total Equity Component	6.2009%

Total Debt Cost Rate:

Long Term Debt	1.4692%
Short Term Debt	0.0448%
Customer Deposits	0.0297%
Deferred ITC - Weighted Cost	0.0977%
Total Debt Component	1.6414%
Total Cost of Capital	7.8423%

Notes:

Column (1) - Per Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology.
Column (2) - Column (1) / Total Column (1)
Column (3) - Per Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology.
Column (4) - Column (2) x Column (3)

TAMPA ELECTRIC COMPANY
DOCKET NO. 20210007-EI
FILED: 08/27/2021

EXHIBIT MAS-3 TO THE TESTIMONY OF M. ASHLEY SIZEMORE

TAMPA ELECTRIC'S ENVIRONMENTAL COST RECOVERY

PROJECTION

JANUARY 2022 THROUGH DECEMBER 2022

INDEX

ENVIRONMENTAL COST RECOVERY

COMMISSION FORMS

JANUARY 2022 THROUGH DECEMBER 2022

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to Be Recovered

Form 42 - 1P

For the Projected Period
January 2022 to December 2022

Line	Energy ($)	Demand ($)	Total ($)
1. Total Jurisdictional Revenue Requirements for the projected period			
a. Projected O&M Activities (Form 42-2P, Lines 7, 8 & 9)	$4,332,767	$81,730	$4,414,497
b. Projected Capital Projects (Form 42-3P, Lines 7, 8 & 9)	42,433,015	4,225,359	46,658,374
c. Total Jurisdictional Revenue Requirements for the projected period (Lines 1a + 1b)	46,765,782	4,307,089	51,072,871
2. True-up for Estimated Over/(Under) Recovery for the current period January 2021 to December 2021 (Form 42-2E, Line 5 + 6 + 10)	(4,161,856)	(127,767)	(4,289,623)
3. Final True-up for the period January 2020 to December 2020 (Form 42-1A, Line 3)	4,199,464	37,727	4,237,191
4. Total Jurisdictional Amount to Be Recovered/(Refunded) in the projection period January 2022 to December 2022 (Line 1 - Line 2- Line 3)	46,728,174	4,397,129	51,125,303
5. Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier)	$46,761,818	$4,400,295	$51,162,113

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Form 42 - 2P

O&M Activities
(in Dollars)

Line		Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	Description of O&M Activities															
	a. Big Bend Unit 3 Flue Gas Desulfurization Integration	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	c. SO_2 Emissions Allowances	(5)	7	7	(5)	7	7	(5)	7	7	(5)	7	7	41		41
	d. Big Bend Units 1 & 2 FGD	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	e. Big Bend PM Minimization and Monitoring	21,630	21,630	21,630	21,630	21,630	21,630	21,630	21,630	21,630	21,630	21,630	21,630	259,560		259,560
	f. Big Bend NO_x Emissions Reduction	174	174	174	174	174	174	174	174	174	174	174	174	2,089		2,089
	g. NPDES Annual Surveillance Fees	0	34,500	0	0	0	0	0	0	0	0	0	0	34,500	$34,500	
	h. Gannon Thermal Discharge Study	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	i. Polk NO_x Emissions Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	j. Bayside SCR and Ammonia	10,200	10,200	11,500	12,500	14,000	15,200	15,200	15,300	14,000	12,500	10,200	10,200	151,000		151,000
	k. Big Bend Unit 4 SOFA	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	l. Big Bend Unit 1 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	m. Big Bend Unit 2 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	n. Big Bend Unit 3 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	o. Clean Water Act Section 316(b) Phase II Study	5,000	0	0	0	2,575	2,575	0	0	0	0	0	0	10,150	10,150	
	p. Arsenic Groundwater Standard Program	3,090	3,090	3,090	3,090	3,090	3,090	3,090	3,090	3,090	3,090	3,090	3,090	37,080	37,080	
	q. Big Bend 1 SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	r. Big Bend 2 SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	s. Big Bend 3 SCR	20,928	9,136	43,640	9,136	35,926	25,553	26,808	30,500	33,748	64,667	43,844	28,637	372,522		372,522
	t. Big Bend 4 SCR	126,564	138,356	103,851	138,356	111,565	121,939	120,683	116,991	113,744	82,825	103,647	118,855	1,397,376		1,397,376
	u. Mercury Air Toxics Standards	0	0	2,000	0	0	0	0	0	0	0	0	0	2,000		2,000
	v. Greenhouse Gas Reduction Program	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	w. Big Bend Gypsum Storage Facility (East 40)	101,103	101,103	101,103	101,103	101,103	101,103	101,103	101,103	101,103	101,103	101,103	101,103	1,213,236		1,213,236
	x. Coal Combustion Residuals (CCR) Rule - Phase I	77,500	77,500	77,500	77,500	77,500	77,500	77,500	77,500	77,500	77,500	77,500	77,500	930,000		930,000
	y. Big Bend ELG Compliance	412	412	412	412	412	412	412	412	412	412	412	412	4,944		4,944
	z. Coal Combustion Residuals (CCR) Rule - Phase II	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	aa. Big Bend Unit 1 Sec. 316(b) Impingement Mortality	0	0	0	0	0	0	0	0	0	0	0	0	0		0
2.	Total of O&M Activities	366,596	396,108	364,908	363,896	367,983	369,183	366,596	366,708	365,408	363,896	361,608	361,608	4,414,497	$81,730	$4,332,767
3.	Recoverable Costs Allocated to Energy	358,506	358,518	361,818	360,806	362,318	363,518	363,506	363,618	362,318	360,806	358,518	358,518	4,332,767		
4.	Recoverable Costs Allocated to Demand	8,090	37,590	3,090	3,090	5,665	5,665	3,090	3,090	3,090	3,090	3,090	3,090	81,730		
5.	Retail Energy Jurisdictional Factor	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
6.	Retail Demand Jurisdictional Factor	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
7.	Jurisdictional Energy Recoverable Costs (A)	358,506	358,518	361,818	360,806	362,318	363,518	363,506	363,618	362,318	360,806	358,518	358,518	4,332,767		
8.	Jurisdictional Demand Recoverable Costs (B)	8,090	37,590	3,090	3,090	5,665	5,665	3,090	3,090	3,090	3,090	3,090	3,090	81,730		
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$366,596	$396,108	$364,908	$363,896	$367,983	$369,183	$366,596	$366,708	$365,408	$363,896	$361,608	$361,608	$4,414,497		

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6

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DOCKET NO. 20210007-EI
ECRC 2022 PROJECTION, FORM 42-2P
EXHIBIT NO. MAS-3 , DOCUMENT NO. 2

Form 42-3P

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line		Description (A)		Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	a.	Big Bend Unit 3 Flue Gas Desulfurization Integration	1	$77,338	$77,137	$76,935	$76,732	$76,530	$76,329	$76,126	$75,924	$75,723	$75,520	$75,318	$75,117	$914,729		$914,729
	b.	Big Bend Units 1 and 2 Flue Gas Conditioning	2	7,734	7,684	7,633	7,583	7,532	7,482	7,431	7,380	7,329	7,280	4,869	0	79,937		79,937
	c.	Big Bend Unit 4 Continuous Emissions Monitors	3	3,795	3,779	3,763	3,746	3,730	3,714	3,698	3,682	3,666	3,650	3,633	3,617	44,473		44,473
	d.	Big Bend Fuel Oil Tank # 1 Upgrade	4	0	0	0	0	0	0	0	0	0	0	0	0	0	$0	
	e.	Big Bend Fuel Oil Tank # 2 Upgrade	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	f.	Big Bend Unit 1 Classifier Replacement	6	5,659	5,629	5,599	5,568	5,537	5,507	5,476	5,445	5,414	5,384	5,353	5,322	65,893		65,893
	g.	Big Bend Unit 2 Classifier Replacement	7	4,147	4,126	4,105	4,084	4,063	4,042	4,019	3,998	3,977	3,956	3,935	3,914	48,366		48,366
	h.	Big Bend Section 114 Mercury Testing Platform	8	674	673	671	668	667	665	663	661	658	657	655	652	7,964		7,964
	i.	Big Bend Units 1 & 2 FGD	9	454,384	452,550	450,715	448,880	447,046	445,211	443,376	441,542	439,707	437,872	436,038	434,203	5,331,524		5,331,524
	j.	Big Bend FGD Optimization and Utilization	10	128,684	128,351	128,017	127,683	127,349	127,016	126,682	126,348	126,014	125,680	125,347	125,013	1,522,184		1,522,184
	k.	Big Bend NO_x Emissions Reduction	11	42,186	42,114	42,044	41,973	41,901	41,830	41,758	41,687	41,615	41,544	41,472	41,402	501,526		501,526
	l.	Big Bend PM Minimization and Monitoring	12	142,974	142,548	142,122	141,695	141,269	140,842	140,416	139,989	139,563	139,137	138,710	138,284	1,687,549		1,687,549
	m.	Polk NO_x Emissions Reduction	13	8,700	8,669	8,638	8,607	8,576	8,545	8,514	8,483	8,453	8,422	8,391	8,360	102,358		102,358
	n.	Big Bend Unit 4 SOFA	14	15,776	15,731	15,686	15,642	15,597	15,552	15,507	15,463	15,418	15,373	15,328	15,283	186,356		186,356
	o.	Big Bend Unit 1 Pre-SCR	15	10,518	10,479	10,441	10,402	10,364	10,325	10,287	10,249	10,210	10,172	10,133	10,095	123,675		123,675
	p.	Big Bend Unit 2 Pre-SCR	16	10,137	10,104	10,069	10,035	10,001	9,966	9,933	9,898	9,864	9,830	9,796	9,761	119,394		119,394
	q.	Big Bend Unit 3 Pre-SCR	17	18,380	18,324	18,268	18,212	18,157	18,101	18,046	17,990	17,934	17,878	17,822	17,766	216,878		216,878
	r.	Big Bend Unit 1 SCR	18	602,472	600,307	598,140	595,975	593,810	591,644	589,479	587,314	585,148	582,982	580,817	578,652	7,086,740		7,086,740
	s.	Big Bend Unit 2 SCR	19	666,864	664,676	662,488	660,300	658,112	655,924	653,736	651,548	649,360	647,172	644,984	642,796	7,857,960		7,857,960
	t.	Big Bend Unit 3 SCR	20	543,457	541,691	539,925	538,159	536,394	534,628	532,863	531,097	529,332	527,566	525,801	524,035	6,404,948		6,404,948
	u.	Big Bend Unit 4 SCR	21	445,135	443,773	442,412	441,050	439,688	438,326	436,965	435,604	434,242	432,880	431,519	430,157	5,251,751		5,251,751
	v.	Big Bend FGD System Reliability	22	173,242	172,881	172,519	172,158	171,797	171,435	171,074	170,713	170,351	169,990	169,629	169,268	2,055,057		2,055,057
	w.	Mercury Air Toxics Standards	23	67,169	67,012	66,856	66,699	66,543	66,387	66,230	66,074	65,917	65,761	65,604	65,448	795,700		795,700
	x.	SO_2 Emissions Allowances (B)	24	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(2,880)		(2,880)
	y.	Big Bend Gypsum Storage Facility	25	171,243	170,880	170,516	170,153	169,789	169,426	169,063	168,699	168,336	167,973	167,609	167,246	2,030,933		2,030,933
	z.	Big Bend Coal Combustion Residual Rule (CCR Rule)	26	38,083	40,465	42,841	46,965	51,619	51,513	51,409	51,303	51,199	51,094	50,989	50,884	578,364	578,364	
	aa.	Coal Combustion Residuals (CCR-Phase II)	27	19,007	18,972	18,937	18,901	18,866	18,831	18,796	18,761	18,726	18,690	18,655	18,620	225,762	225,762	
	ab.	Big Bend ELG Compliance	28	98,581	110,209	119,912	127,618	136,200	200,483	207,483	220,721	240,587	249,881	253,175	256,668	2,221,518	2,221,518	
	ac.	Big Bend Unit 1 Impingement Mortality - 316(b)	29	91,850	94,769	97,157	99,710	101,574	102,057	102,084	102,102	102,103	102,103	102,103	102,103	1,199,715	1,199,715	
2.		Total Investment Projects - Recoverable Costs		3,847,949	3,853,293	3,856,169	3,858,958	3,862,471	3,915,541	3,910,874	3,912,435	3,920,606	3,918,207	3,907,445	3,894,426	46,658,374	$4,225,359	$42,433,015
3.		Recoverable Costs Allocated to Energy		3,600,428	3,588,878	3,577,322	3,565,764	3,554,212	3,542,657	3,531,102	3,519,548	3,507,991	3,496,439	3,482,523	3,466,151	42,433,015		42,433,015
4.		Recoverable Costs Allocated to Demand		247,521	264,415	278,847	293,194	308,259	372,884	379,772	392,887	412,615	421,768	424,922	428,275	4,225,359	4,225,359	
5.		Retail Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
6.		Retail Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
7.		Jurisdictional Energy Recoverable Costs (C)		3,600,428	3,588,878	3,577,322	3,565,764	3,554,212	3,542,657	3,531,102	3,519,548	3,507,991	3,496,439	3,482,523	3,466,151	42,433,015		
8.		Jurisdictional Demand Recoverable Costs (D)		247,521	264,415	278,847	293,194	308,259	372,884	379,772	392,887	412,615	421,768	424,922	428,275	4,225,359		
9.		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)		$3,847,949	$3,853,293	$3,856,169	$3,858,958	$3,862,471	$3,915,541	$3,910,874	$3,912,435	$3,920,606	$3,918,207	$3,907,445	$3,894,426	$46,658,374		

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-4P, Line 9
(B) Project's Total Return Component on Form 42-4P, Line 6
(C) Line 3 x Line 5
(D) Line 4 x Line 6

DOCKET NO. 20210007-EI
ECRC 2022 PROJECTION, FORM 42-3P
EXHIBIT NO. MAS-3 , DOCUMENT NO. 3

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Flue Gas Desulfurization Integration
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	
3.	Less: Accumulated Depreciation	(6,824,505)	(6,853,343)	(6,882,181)	(6,911,019)	(6,939,857)	(6,968,695)	(6,997,533)	(7,026,371)	(7,055,209)	(7,084,047)	(7,112,885)	(7,141,723)	(7,170,561)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$6,938,758	6,909,920	6,881,082	6,852,244	6,823,406	6,794,568	6,765,730	6,736,892	6,708,054	6,679,216	6,650,378	6,621,540	6,592,702	
6.	Average Net Investment		6,924,339	6,895,501	6,866,663	6,837,825	6,808,987	6,780,149	6,751,311	6,722,473	6,693,635	6,664,797	6,635,959	6,607,121	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$39,064	$38,902	$38,739	$38,576	$38,413	$38,251	$38,088	$37,925	$37,763	$37,600	$37,437	$37,275	$458,033
	b. Debt Component Grossed Up For Taxes (C)		9,436	9,397	9,358	9,318	9,279	9,240	9,200	9,161	9,122	9,082	9,043	9,004	110,640
8.	Investment Expenses														
	a. Depreciation (D)		28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	346,056
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		77,338	77,137	76,935	76,732	76,530	76,329	76,126	75,924	75,723	75,520	75,318	75,117	914,729
	a. Recoverable Costs Allocated to Energy		77,338	77,137	76,935	76,732	76,530	76,329	76,126	75,924	75,723	75,520	75,318	75,117	914,729
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		77,338	77,137	76,935	76,732	76,530	76,329	76,126	75,924	75,723	75,520	75,318	75,117	914,729
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$77,338	$77,137	$76,935	$76,732	$76,530	$76,329	$76,126	$75,924	$75,723	$75,520	$75,318	$75,117	$914,729

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.45 ($13,435,775), 315.45 ($327,307), and 312.40 ($182).
(B) Line 6 x 6.7699% x 1/12. Based on ROE of 10.75% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 2.5%, 3.1%, and 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 Flue Gas Conditioning
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	
3.	Less: Accumulated Depreciation	(4,940,682)	(4,947,902)	(4,955,122)	(4,962,342)	(4,969,562)	(4,976,782)	(4,984,002)	(4,991,222)	(4,998,442)	(5,005,662)	(5,012,882)	(5,017,734)	(5,017,734)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$77,052	69,832	62,612	55,392	48,172	40,952	33,732	26,512	19,292	12,072	4,852	0	0	
6.	Average Net Investment		73,442	66,222	59,002	51,782	44,562	37,342	30,122	22,902	15,682	8,462	2,426	0	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$414	$374	$333	$292	$251	$211	$170	$129	$88	$48	$14	$0	$2,324
	b. Debt Component Grossed Up For Taxes (C)		100	90	80	71	61	51	41	31	21	12	3	0	561
8.	Investment Expenses														
	a. Depreciation (D)		7,220	7,220	7,220	7,220	7,220	7,220	7,220	7,220	7,220	7,220	4,852	0	77,052
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		7,734	7,684	7,633	7,583	7,532	7,482	7,431	7,380	7,329	7,280	4,869	0	79,937
	a. Recoverable Costs Allocated to Energy		7,734	7,684	7,633	7,583	7,532	7,482	7,431	7,380	7,329	7,280	4,869	0	79,937
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		7,734	7,684	7,633	7,583	7,532	7,482	7,431	7,380	7,329	7,280	4,869	0	79,937
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$7,734	$7,684	$7,633	$7,583	$7,532	$7,482	$7,431	$7,380	$7,329	$7,280	$4,869	$0	$79,937

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($2,676,217) and 312.42 ($2,341,517).
(B) Line 6 x 6.7699% x 1/12. Based on ROE of 10.75% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 4.0% and 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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DOCKET NO. 20210007-EI
ECRC 2022 PROJECTION, FORM 42-4P
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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 Continuous Emissions Monitors
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	
3.	Less: Accumulated Depreciation	(653,045)	(655,355)	(657,665)	(659,975)	(662,285)	(664,595)	(666,905)	(669,215)	(671,525)	(673,835)	(676,145)	(678,455)	(680,765)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$213,166	210,856	208,546	206,236	203,926	201,616	199,306	196,996	194,686	192,376	190,066	187,756	185,446	
6.	Average Net Investment		212,011	209,701	207,391	205,081	202,771	200,461	198,151	195,841	193,531	191,221	188,911	186,601	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,196	$1,183	$1,170	$1,157	$1,144	$1,131	$1,118	$1,105	$1,092	$1,079	$1,066	$1,053	$13,494
	b. Debt Component Grossed Up For Taxes (C)		289	286	283	279	276	273	270	267	264	261	257	254	3,259
8.	Investment Expenses														
	a. Depreciation (D)		2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	27,720
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		3,795	3,779	3,763	3,746	3,730	3,714	3,698	3,682	3,666	3,650	3,633	3,617	44,473
	a. Recoverable Costs Allocated to Energy		3,795	3,779	3,763	3,746	3,730	3,714	3,698	3,682	3,666	3,650	3,633	3,617	44,473
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		3,795	3,779	3,763	3,746	3,730	3,714	3,698	3,682	3,666	3,650	3,633	3,617	44,473
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$3,795	$3,779	$3,763	$3,746	$3,730	$3,714	$3,698	$3,682	$3,666	$3,650	$3,633	$3,617	$44,473

Notes:
(A) Applicable depreciable base for Big Bend; account 315.44
(B) Line 6 x 6.7699% x 1/12. Based on ROE of 10.75% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 3.2%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 1 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	
3.	Less: Accumulated Depreciation	(497,578)	(497,578)	(497,578)	(497,578)	(497,578)	(497,578)	(497,578)	(497,578)	(497,578)	(497,578)	(497,578)	(497,578)	(497,578)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	0	0	0	0	0	0	
6.	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Debt Component Grossed Up For Taxes (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Investment Expenses														
	a. Depreciation (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 6.7699% x 1/12. Based on ROE of 10.75% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 12.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 2 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	
3.	Less: Accumulated Depreciation	(818,401)	(818,401)	(818,401)	(818,401)	(818,401)	(818,401)	(818,401)	(818,401)	(818,401)	(818,401)	(818,401)	(818,401)	(818,401)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	0	0	0	0	0	0	
6.	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Debt Component Grossed Up For Taxes (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Investment Expenses														
	a. Depreciation (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 6.7699% x 1/12. Based on ROE of 10.75% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 12.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	
3.	Less: Accumulated Depreciation	(1,132,472)	(1,136,860)	(1,141,248)	(1,145,636)	(1,150,024)	(1,154,412)	(1,158,800)	(1,163,188)	(1,167,576)	(1,171,964)	(1,176,352)	(1,180,740)	(1,185,128)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$183,785	179,397	175,009	170,621	166,233	161,845	157,457	153,069	148,681	144,293	139,905	135,517	131,129	
6.	Average Net Investment		181,591	177,203	172,815	168,427	164,039	159,651	155,263	150,875	146,487	142,099	137,711	133,323	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,024	$1,000	$975	$950	$925	$901	$876	$851	$826	$802	$777	$752	$10,659
	b. Debt Component Grossed Up For Taxes (C)		247	241	236	230	224	218	212	206	200	194	188	182	2,578
8.	Investment Expenses														
	a. Depreciation (D)		4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	52,656
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		5,659	5,629	5,599	5,568	5,537	5,507	5,476	5,445	5,414	5,384	5,353	5,322	65,893
	a. Recoverable Costs Allocated to Energy		5,659	5,629	5,599	5,568	5,537	5,507	5,476	5,445	5,414	5,384	5,353	5,322	65,893
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		5,659	5,629	5,599	5,568	5,537	5,507	5,476	5,445	5,414	5,384	5,353	5,322	65,893
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$5,659	$5,629	$5,599	$5,568	$5,537	$5,507	$5,476	$5,445	$5,414	$5,384	$5,353	$5,322	$65,893

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 6.7699% x 1/12. Based on ROE of 10.75% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 4.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DOCKET NO. 20210007-EI
ECRC 2022 PROJECTION, FORM 42-4P
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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	
3.	Less: Accumulated Depreciation	(824,598)	(827,634)	(830,670)	(833,706)	(836,742)	(839,778)	(842,814)	(845,850)	(848,886)	(851,922)	(854,958)	(857,994)	(861,030)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$160,196	157,160	154,124	151,088	148,052	145,016	141,980	138,944	135,908	132,872	129,836	126,800	123,764	
6.	Average Net Investment		158,678	155,642	152,606	149,570	146,534	143,498	140,462	137,426	134,390	131,354	128,318	125,282	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$895	$878	$861	$844	$827	$810	$792	$775	$758	$741	$724	$707	$9,612
	b. Debt Component Grossed Up For Taxes (C)		216	212	208	204	200	196	191	187	183	179	175	171	2,322
8.	Investment Expenses														
	a. Depreciation (D)		3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	36,432
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		4,147	4,126	4,105	4,084	4,063	4,042	4,019	3,998	3,977	3,956	3,935	3,914	48,366
	a. Recoverable Costs Allocated to Energy		4,147	4,126	4,105	4,084	4,063	4,042	4,019	3,998	3,977	3,956	3,935	3,914	48,366
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		4,147	4,126	4,105	4,084	4,063	4,042	4,019	3,998	3,977	3,956	3,935	3,914	48,366
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
15	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$4,147	$4,126	$4,105	$4,084	$4,063	$4,042	$4,019	$3,998	$3,977	$3,956	$3,935	$3,914	$48,366

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 6.7699% x 1/12. Based on ROE of 10.75% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Section 114 Mercury Testing Platform
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	
3.	Less: Accumulated Depreciation	(65,923)	(66,215)	(66,507)	(66,799)	(67,091)	(67,383)	(67,675)	(67,967)	(68,259)	(68,551)	(68,843)	(69,135)	(69,427)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$54,814	54,522	54,230	53,938	53,646	53,354	53,062	52,770	52,478	52,186	51,894	51,602	51,310	
6.	Average Net Investment		54,668	54,376	54,084	53,792	53,500	53,208	52,916	52,624	52,332	52,040	51,748	51,456	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$308	$307	$305	$303	$302	$300	$299	$297	$295	$294	$292	$290	$3,592
	b. Debt Component Grossed Up For Taxes (C)		74	74	74	73	73	73	72	72	71	71	71	70	868
8.	Investment Expenses														
	a. Depreciation (D)		292	292	292	292	292	292	292	292	292	292	292	292	3,504
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		674	673	671	668	667	665	663	661	658	657	655	652	7,964
	a. Recoverable Costs Allocated to Energy		674	673	671	668	667	665	663	661	658	657	655	652	7,964
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		674	673	671	668	667	665	663	661	658	657	655	652	7,964
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$674	$673	$671	$668	$667	$665	$663	$661	$658	$657	$655	$652	$7,964

Notes:
(A) Applicable depreciable base for Big Bend; account 311.40
(B) Line 6 x 6.7699% x 1/12. Based on ROE of 10.75% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 2.9%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 FGD
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	
3.	Less: Accumulated Depreciation	(67,646,321)	(67,908,240)	(68,170,159)	(68,432,078)	(68,693,997)	(68,955,916)	(69,217,835)	(69,479,754)	(69,741,673)	(70,003,592)	(70,265,511)	(70,527,430)	(70,789,349)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$27,608,921	27,347,002	27,085,083	26,823,164	26,561,245	26,299,326	26,037,407	25,775,488	25,513,569	25,251,650	24,989,731	24,727,812	24,465,893	
6.	Average Net Investment		27,477,961	27,216,042	26,954,123	26,692,204	26,430,285	26,168,366	25,906,447	25,644,528	25,382,609	25,120,690	24,858,771	24,596,852	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$155,019	$153,542	$152,064	$150,586	$149,109	$147,631	$146,153	$144,676	$143,198	$141,720	$140,243	$138,765	$1,762,706
	b. Debt Component Grossed Up For Taxes (C)		37,446	37,089	36,732	36,375	36,018	35,661	35,304	34,947	34,590	34,233	33,876	33,519	425,790
8.	Investment Expenses														
	a. Depreciation (D)		261,919	261,919	261,919	261,919	261,919	261,919	261,919	261,919	261,919	261,919	261,919	261,919	3,143,028
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		454,384	452,550	450,715	448,880	447,046	445,211	443,376	441,542	439,707	437,872	436,038	434,203	5,331,524
	a. Recoverable Costs Allocated to Energy		454,384	452,550	450,715	448,880	447,046	445,211	443,376	441,542	439,707	437,872	436,038	434,203	5,331,524
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		454,384	452,550	450,715	448,880	447,046	445,211	443,376	441,542	439,707	437,872	436,038	434,203	5,331,524
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$454,384	$452,550	$450,715	$448,880	$447,046	$445,211	$443,376	$441,542	$439,707	$437,872	$436,038	$434,203	$5,331,524

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.46 ($94,929,061), 312.45 ($105,398), and 315.46 ($220,782).
(B) Line 6 x 6.7699% x 1/12. Based on ROE of 10.75% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 3.3%, 2.5%, and 3.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD Optimization and Utilization
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	
3.	Less: Accumulated Depreciation	(11,060,534)	(11,108,181)	(11,155,828)	(11,203,475)	(11,251,122)	(11,298,769)	(11,346,416)	(11,394,063)	(11,441,710)	(11,489,357)	(11,537,004)	(11,584,651)	(11,632,298)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$11,593,395	11,545,748	11,498,101	11,450,454	11,402,807	11,355,160	11,307,513	11,259,866	11,212,219	11,164,572	11,116,925	11,069,278	11,021,631	
6.	Average Net Investment		11,569,572	11,521,925	11,474,278	11,426,631	11,378,984	11,331,337	11,283,690	11,236,043	11,188,396	11,140,749	11,093,102	11,045,455	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$65,271	$65,002	$64,733	$64,464	$64,195	$63,927	$63,658	$63,389	$63,120	$62,851	$62,583	$62,314	$765,507
	b. Debt Component Grossed Up For Taxes (C)		15,766	15,702	15,637	15,572	15,507	15,442	15,377	15,312	15,247	15,182	15,117	15,052	184,913
8.	Investment Expenses														
	a. Depreciation (D)		47,647	47,647	47,647	47,647	47,647	47,647	47,647	47,647	47,647	47,647	47,647	47,647	571,764
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		128,684	128,351	128,017	127,683	127,349	127,016	126,682	126,348	126,014	125,680	125,347	125,013	1,522,184
	a. Recoverable Costs Allocated to Energy		128,684	128,351	128,017	127,683	127,349	127,016	126,682	126,348	126,014	125,680	125,347	125,013	1,522,184
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		128,684	128,351	128,017	127,683	127,349	127,016	126,682	126,348	126,014	125,680	125,347	125,013	1,522,184
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$128,684	$128,351	$128,017	$127,683	$127,349	$127,016	$126,682	$126,348	$126,014	$125,680	$125,347	$125,013	$1,522,184

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.45 ($21,855,886), 311.45 ($40,016), 316.40 ($71,401), 315.45 ($594,901), 312.42 ($1,637), and 312.40 ($90,088).
(B) Line 6 x 6.7699% x 1/12. Based on ROE of 10.75% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 2.5%, 2.0%, 4.2%, 3.1%, 3.7%, and 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	
3.	Less: Accumulated Depreciation	1,383,147	1,372,963	1,362,779	1,352,595	1,342,411	1,332,227	1,322,043	1,311,859	1,301,675	1,291,491	1,281,307	1,271,123	1,260,939	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$4,573,999	4,563,815	4,553,631	4,543,447	4,533,263	4,523,079	4,512,895	4,502,711	4,492,527	4,482,343	4,472,159	4,461,975	4,451,791	
6.	Average Net Investment		4,568,907	4,558,723	4,548,539	4,538,355	4,528,171	4,517,987	4,507,803	4,497,619	4,487,435	4,477,251	4,467,067	4,456,883	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$25,776	$25,718	$25,661	$25,604	$25,546	$25,489	$25,431	$25,374	$25,316	$25,259	$25,201	$25,144	$305,519
	b. Debt Component Grossed Up For Taxes (C)		6,226	6,212	6,199	6,185	6,171	6,157	6,143	6,129	6,115	6,101	6,087	6,074	73,799
8.	Investment Expenses														
	a. Depreciation (D)		10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	122,208
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		42,186	42,114	42,044	41,973	41,901	41,830	41,758	41,687	41,615	41,544	41,472	41,402	501,526
	a. Recoverable Costs Allocated to Energy		42,186	42,114	42,044	41,973	41,901	41,830	41,758	41,687	41,615	41,544	41,472	41,402	501,526
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		42,186	42,114	42,044	41,973	41,901	41,830	41,758	41,687	41,615	41,544	41,472	41,402	501,526
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$42,186	$42,114	$42,044	$41,973	$41,901	$41,830	$41,758	$41,687	$41,615	$41,544	$41,472	$41,402	$501,526

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,675,171), 312.42 ($1,075,718), and 312.43 ($439,963).
(B) Line 6 x 6.7699% x 1/12. Based on ROE of 10.75% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 4.0%, 3.7%, and 3.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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ECRC 2022 PROJECTION, FORM 42-4P
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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: PM Minimization and Monitoring
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	
3.	Less: Accumulated Depreciation	(8,005,714)	(8,066,586)	(8,127,458)	(8,188,330)	(8,249,202)	(8,310,074)	(8,370,946)	(8,431,818)	(8,492,690)	(8,553,562)	(8,614,434)	(8,675,306)	(8,736,178)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$11,752,036	11,691,164	11,630,292	11,569,420	11,508,548	11,447,676	11,386,804	11,325,932	11,265,060	11,204,188	11,143,316	11,082,444	11,021,572	
6.	Average Net Investment		11,721,600	11,660,728	11,599,856	11,538,984	11,478,112	11,417,240	11,356,368	11,295,496	11,234,624	11,173,752	11,112,880	11,052,008	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$66,128	$65,785	$65,442	$65,098	$64,755	$64,411	$64,068	$63,724	$63,381	$63,038	$62,694	$62,351	$770,875
	b. Debt Component Grossed Up For Taxes (C)		15,974	15,891	15,808	15,725	15,642	15,559	15,476	15,393	15,310	15,227	15,144	15,061	186,210
8.	Investment Expenses														
	a. Depreciation (D)		60,872	60,872	60,872	60,872	60,872	60,872	60,872	60,872	60,872	60,872	60,872	60,872	730,464
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		142,974	142,548	142,122	141,695	141,269	140,842	140,416	139,989	139,563	139,137	138,710	138,284	1,687,549
	a. Recoverable Costs Allocated to Energy		142,974	142,548	142,122	141,695	141,269	140,842	140,416	139,989	139,563	139,137	138,710	138,284	1,687,549
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		142,974	142,548	142,122	141,695	141,269	140,842	140,416	139,989	139,563	139,137	138,710	138,284	1,687,549
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$142,974	$142,548	$142,122	$141,695	$141,269	$140,842	$140,416	$139,989	$139,563	$139,137	$138,710	$138,284	$1,687,549

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($5,831,465), 312.42 ($5,153,072), 312.43 ($7,875,560), 315.41 ($17,504), 315.44 ($351,594), and 315.43 ($528,554).
(B) Line 6 x 6.7699% x 1/12. Based on ROE of 10.75% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 4.0%, 3.7%, 3.5%, 3.5%, 3.2%, and 3.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Polk NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	
3.	Less: Accumulated Depreciation	(948,762)	(953,186)	(957,610)	(962,034)	(966,458)	(970,882)	(975,306)	(979,730)	(984,154)	(988,578)	(993,002)	(997,426)	(1,001,850)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$612,711	608,287	603,863	599,439	595,015	590,591	586,167	581,743	577,319	572,895	568,471	564,047	559,623	
6.	Average Net Investment		610,499	606,075	601,651	597,227	592,803	588,379	583,955	579,531	575,107	570,683	566,259	561,835	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$3,444	$3,419	$3,394	$3,369	$3,344	$3,319	$3,294	$3,269	$3,245	$3,220	$3,195	$3,170	$39,682
	b. Debt Component Grossed Up For Taxes (C)		832	826	820	814	808	802	796	790	784	778	772	766	9,588
8.	Investment Expenses														
	a. Depreciation (D)		4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	53,088
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		8,700	8,669	8,638	8,607	8,576	8,545	8,514	8,483	8,453	8,422	8,391	8,360	102,358
	a. Recoverable Costs Allocated to Energy		8,700	8,669	8,638	8,607	8,576	8,545	8,514	8,483	8,453	8,422	8,391	8,360	102,358
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		8,700	8,669	8,638	8,607	8,576	8,545	8,514	8,483	8,453	8,422	8,391	8,360	102,358
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$8,700	$8,669	$8,638	$8,607	$8,576	$8,545	$8,514	$8,483	$8,453	$8,422	$8,391	$8,360	$102,358

Notes:
(A) Applicable depreciable base for Polk; account 342.81
(B) Line 6 x 6.7699% x 1/12. Based on ROE of 10.75% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SOFA
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	
3.	Less: Accumulated Depreciation	(1,216,490)	(1,222,887)	(1,229,284)	(1,235,681)	(1,242,078)	(1,248,475)	(1,254,872)	(1,261,269)	(1,267,666)	(1,274,063)	(1,280,460)	(1,286,857)	(1,293,254)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,342,240	1,335,843	1,329,446	1,323,049	1,316,652	1,310,255	1,303,858	1,297,461	1,291,064	1,284,667	1,278,270	1,271,873	1,265,476	
6.	Average Net Investment		1,339,042	1,332,645	1,326,248	1,319,851	1,313,454	1,307,057	1,300,660	1,294,263	1,287,866	1,281,469	1,275,072	1,268,675	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$7,554	$7,518	$7,482	$7,446	$7,410	$7,374	$7,338	$7,302	$7,266	$7,230	$7,193	$7,157	$88,270
	b. Debt Component Grossed Up For Taxes (C)		1,825	1,816	1,807	1,799	1,790	1,781	1,772	1,764	1,755	1,746	1,738	1,729	21,322
8.	Investment Expenses														
	a. Depreciation (D)		6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	76,764
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		15,776	15,731	15,686	15,642	15,597	15,552	15,507	15,463	15,418	15,373	15,328	15,283	186,356
	a. Recoverable Costs Allocated to Energy		15,776	15,731	15,686	15,642	15,597	15,552	15,507	15,463	15,418	15,373	15,328	15,283	186,356
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		15,776	15,731	15,686	15,642	15,597	15,552	15,507	15,463	15,418	15,373	15,328	15,283	186,356
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$15,776	$15,731	$15,686	$15,642	$15,597	$15,552	$15,507	$15,463	$15,418	$15,373	$15,328	$15,283	$186,356

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44
(B) Line 6 x 6.7699% x 1/12. Based on ROE of 10.75% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	
3.	Less: Accumulated Depreciation	(929,485)	(934,982)	(940,479)	(945,976)	(951,473)	(956,970)	(962,467)	(967,964)	(973,461)	(978,958)	(984,455)	(989,952)	(995,449)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$719,636	714,139	708,642	703,145	697,648	692,151	686,654	681,157	675,660	670,163	664,666	659,169	653,672	
6.	Average Net Investment		716,888	711,391	705,894	700,397	694,900	689,403	683,906	678,409	672,912	667,415	661,918	656,421	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$4,044	$4,013	$3,982	$3,951	$3,920	$3,889	$3,858	$3,827	$3,796	$3,765	$3,734	$3,703	$46,482
	b. Debt Component Grossed Up For Taxes (C)		977	969	962	954	947	939	932	925	917	910	902	895	11,229
8.	Investment Expenses														
	a. Depreciation (D)		5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	65,964
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		10,518	10,479	10,441	10,402	10,364	10,325	10,287	10,249	10,210	10,172	10,133	10,095	123,675
	a. Recoverable Costs Allocated to Energy		10,518	10,479	10,441	10,402	10,364	10,325	10,287	10,249	10,210	10,172	10,133	10,095	123,675
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		10,518	10,479	10,441	10,402	10,364	10,325	10,287	10,249	10,210	10,172	10,133	10,095	123,675
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$10,518	$10,479	$10,441	$10,402	$10,364	$10,325	$10,287	$10,249	$10,210	$10,172	$10,133	$10,095	$123,675

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 6.7699% x 1/12. Based on ROE of 10.75% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 4.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	
3.	Less: Accumulated Depreciation	(828,416)	(833,293)	(838,170)	(843,047)	(847,924)	(852,801)	(857,678)	(862,555)	(867,432)	(872,309)	(877,186)	(882,063)	(886,940)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$753,471	748,594	743,717	738,840	733,963	729,086	724,209	719,332	714,455	709,578	704,701	699,824	694,947	
6.	Average Net Investment		751,033	746,156	741,279	736,402	731,525	726,648	721,771	716,894	712,017	707,140	702,263	697,386	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$4,237	$4,210	$4,182	$4,154	$4,127	$4,099	$4,072	$4,044	$4,017	$3,989	$3,962	$3,934	$49,027
	b. Debt Component Grossed Up For Taxes (C)		1,023	1,017	1,010	1,004	997	990	984	977	970	964	957	950	11,843
8.	Investment Expenses														
	a. Depreciation (D)		4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	58,524
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		10,137	10,104	10,069	10,035	10,001	9,966	9,933	9,898	9,864	9,830	9,796	9,761	119,394
	a. Recoverable Costs Allocated to Energy		10,137	10,104	10,069	10,035	10,001	9,966	9,933	9,898	9,864	9,830	9,796	9,761	119,394
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		10,137	10,104	10,069	10,035	10,001	9,966	9,933	9,898	9,864	9,830	9,796	9,761	119,394
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$10,137	$10,104	$10,069	$10,035	$10,001	$9,966	$9,933	$9,898	$9,864	$9,830	$9,796	$9,761	$119,394

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 6.7699% x 1/12. Based on ROE of 10.75% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	
3.	Less: Accumulated Depreciation	(1,213,946)	(1,221,899)	(1,229,852)	(1,237,805)	(1,245,758)	(1,253,711)	(1,261,664)	(1,269,617)	(1,277,570)	(1,285,523)	(1,293,476)	(1,301,429)	(1,309,382)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,492,561	1,484,608	1,476,655	1,468,702	1,460,749	1,452,796	1,444,843	1,436,890	1,428,937	1,420,984	1,413,031	1,405,078	1,397,125	
6.	Average Net Investment		1,488,585	1,480,632	1,472,679	1,464,726	1,456,773	1,448,820	1,440,867	1,432,914	1,424,961	1,417,008	1,409,055	1,401,102	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$8,398	$8,353	$8,308	$8,263	$8,219	$8,174	$8,129	$8,084	$8,039	$7,994	$7,949	$7,904	$97,814
	b. Debt Component Grossed Up For Taxes (C)		2,029	2,018	2,007	1,996	1,985	1,974	1,964	1,953	1,942	1,931	1,920	1,909	23,628
8.	Investment Expenses														
	a. Depreciation (D)		7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	95,436
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		18,380	18,324	18,268	18,212	18,157	18,101	18,046	17,990	17,934	17,878	17,822	17,766	216,878
	a. Recoverable Costs Allocated to Energy		18,380	18,324	18,268	18,212	18,157	18,101	18,046	17,990	17,934	17,878	17,822	17,766	216,878
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		18,380	18,324	18,268	18,212	18,157	18,101	18,046	17,990	17,934	17,878	17,822	17,766	216,878
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$18,380	$18,324	$18,268	$18,212	$18,157	$18,101	$18,046	$17,990	$17,934	$17,878	$17,822	$17,766	$216,878

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.43 ($1,995,677) and 315.43 ($710,830).
(B) Line 6 x 6.7699% x 1/12. Based on ROE of 10.75% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 3.5% and 3.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	
3.	Less: Accumulated Depreciation	(43,689,606)	(43,998,772)	(44,307,938)	(44,617,104)	(44,926,270)	(45,235,436)	(45,544,602)	(45,853,768)	(46,162,934)	(46,472,100)	(46,781,266)	(47,090,432)	(47,399,598)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$42,029,496	41,720,330	41,411,164	41,101,998	40,792,832	40,483,666	40,174,500	39,865,334	39,556,168	39,247,002	38,937,836	38,628,670	38,319,504	
6.	Average Net Investment		41,874,913	41,565,747	41,256,581	40,947,415	40,638,249	40,329,083	40,019,917	39,710,751	39,401,585	39,092,419	38,783,253	38,474,087	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$236,241	$234,497	$232,752	$231,008	$229,264	$227,520	$225,776	$224,032	$222,287	$220,543	$218,799	$217,055	$2,719,774
	b. Debt Component Grossed Up For Taxes (C)		57,065	56,644	56,222	55,801	55,380	54,958	54,537	54,116	53,695	53,273	52,852	52,431	656,974
8.	Investment Expenses														
	a. Depreciation (D)		309,166	309,166	309,166	309,166	309,166	309,166	309,166	309,166	309,166	309,166	309,166	309,166	3,709,992
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		602,472	600,307	598,140	595,975	593,810	591,644	589,479	587,314	585,148	582,982	580,817	578,652	7,086,740
	a. Recoverable Costs Allocated to Energy		602,472	600,307	598,140	595,975	593,810	591,644	589,479	587,314	585,148	582,982	580,817	578,652	7,086,740
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		602,472	600,307	598,140	595,975	593,810	591,644	589,479	587,314	585,148	582,982	580,817	578,652	7,086,740
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$602,472	$600,307	$598,140	$595,975	$593,810	$591,644	$589,479	$587,314	$585,148	$582,982	$580,817	$578,652	$7,086,740

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.51 ($22,278,982), 312.51 ($48,529,672), 315.51 ($14,063,245), and 316.51 ($847,203).
(B) Line 6 x 6.7699% x 1/12. Based on ROE of 10.75% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 4.1%, 4.3%, 4.8%, and 4.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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DOCKET NO. 20210007-EI
ECRC 2022 PROJECTION, FORM 42-4P
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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	
3.	Less: Accumulated Depreciation	(45,772,284)	(46,084,661)	(46,397,038)	(46,709,415)	(47,021,792)	(47,334,169)	(47,646,546)	(47,958,923)	(48,271,300)	(48,583,677)	(48,896,054)	(49,208,431)	(49,520,808)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$50,765,849	50,453,472	50,141,095	49,828,718	49,516,341	49,203,964	48,891,587	48,579,210	48,266,833	47,954,456	47,642,079	47,329,702	47,017,325	
6.	Average Net Investment		50,609,660	50,297,283	49,984,906	49,672,529	49,360,152	49,047,775	48,735,398	48,423,021	48,110,644	47,798,267	47,485,890	47,173,513	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$285,519	$283,756	$281,994	$280,232	$278,469	$276,707	$274,945	$273,183	$271,420	$269,658	$267,896	$266,133	$3,309,912
	b. Debt Component Grossed Up For Taxes (C)		68,968	68,543	68,117	67,691	67,266	66,840	66,414	65,988	65,563	65,137	64,711	64,286	799,524
8.	Investment Expenses														
	a. Depreciation (D)		312,377	312,377	312,377	312,377	312,377	312,377	312,377	312,377	312,377	312,377	312,377	312,377	3,748,524
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		666,864	664,676	662,488	660,300	658,112	655,924	653,736	651,548	649,360	647,172	644,984	642,796	7,857,960
	a. Recoverable Costs Allocated to Energy		666,864	664,676	662,488	660,300	658,112	655,924	653,736	651,548	649,360	647,172	644,984	642,796	7,857,960
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		666,864	664,676	662,488	660,300	658,112	655,924	653,736	651,548	649,360	647,172	644,984	642,796	7,857,960
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$666,864	$664,676	$662,488	$660,300	$658,112	$655,924	$653,736	$651,548	$649,360	$647,172	$644,984	$642,796	$7,857,960

Notes:
(A) Applicable depreciable base for Big Bend; account 311.52 ($25,208,869), 312.52 ($54,456,221), 315.52 ($15,914,427), and 316.52 ($958,616).
(B) Line 6 x 6.7699% x 1/12. Based on ROE of 10.75% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rates are 3.5%, 4.0%, 4.1% and 3.7%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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DOCKET NO. 20210007-EI
ECRC 2022 PROJECTION, FORM 42-4P
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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	
3.	Less: Accumulated Depreciation	(40,038,249)	(40,290,323)	(40,542,397)	(40,794,471)	(41,046,545)	(41,298,619)	(41,550,693)	(41,802,767)	(42,054,841)	(42,306,915)	(42,558,989)	(42,811,063)	(43,063,137)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$41,726,353	41,474,279	41,222,205	40,970,131	40,718,057	40,465,983	40,213,909	39,961,835	39,709,761	39,457,687	39,205,613	38,953,539	38,701,465	
6.	Average Net Investment		41,600,316	41,348,242	41,096,168	40,844,094	40,592,020	40,339,946	40,087,872	39,835,798	39,583,724	39,331,650	39,079,576	38,827,502	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$234,692	$233,270	$231,847	$230,425	$229,003	$227,581	$226,159	$224,737	$223,315	$221,893	$220,471	$219,049	$2,722,442
	b. Debt Component Grossed Up For Taxes (C)		56,691	56,347	56,004	55,660	55,317	54,973	54,630	54,286	53,943	53,599	53,256	52,912	657,618
8.	Investment Expenses														
	a. Depreciation (D)		252,074	252,074	252,074	252,074	252,074	252,074	252,074	252,074	252,074	252,074	252,074	252,074	3,024,888
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		543,457	541,691	539,925	538,159	536,394	534,628	532,863	531,097	529,332	527,566	525,801	524,035	6,404,948
	a. Recoverable Costs Allocated to Energy		543,457	541,691	539,925	538,159	536,394	534,628	532,863	531,097	529,332	527,566	525,801	524,035	6,404,948
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		543,457	541,691	539,925	538,159	536,394	534,628	532,863	531,097	529,332	527,566	525,801	524,035	6,404,948
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$543,457	$541,691	$539,925	$538,159	$536,394	$534,628	$532,863	$531,097	$529,332	$527,566	$525,801	$524,035	$6,404,948

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.53 ($21,689,422), 312.53 ($45,559,543), 315.53 ($13,690,954), and 316.53 ($824,684).
(B) Line 6 x 6.7699% x 1/12. Based on ROE of 10.75% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 3.1%, 3.9%, 4.0%, and 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$67,588,833	$67,588,833	$67,588,833	$67,588,833	$67,588,833	$67,588,833	$67,588,833	$67,588,833	$67,588,833	$67,588,833	$67,588,833	$67,588,833	$67,588,833	
3.	Less: Accumulated Depreciation	(31,694,919)	(31,889,322)	(32,083,725)	(32,278,128)	(32,472,531)	(32,666,934)	(32,861,337)	(33,055,740)	(33,250,143)	(33,444,546)	(33,638,949)	(33,833,352)	(34,027,755)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$35,893,914	35,699,511	35,505,108	35,310,705	35,116,302	34,921,899	34,727,496	34,533,093	34,338,690	34,144,287	33,949,884	33,755,481	33,561,078	
6.	Average Net Investment		35,796,713	35,602,310	35,407,907	35,213,504	35,019,101	34,824,698	34,630,295	34,435,892	34,241,489	34,047,086	33,852,683	33,658,280	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$201,950	$200,853	$199,757	$198,660	$197,563	$196,466	$195,370	$194,273	$193,176	$192,079	$190,983	$189,886	$2,351,016
	b. Debt Component Grossed Up For Taxes (C)		48,782	48,517	48,252	47,987	47,722	47,457	47,192	46,928	46,663	46,398	46,133	45,868	567,899
8.	Investment Expenses														
	a. Depreciation (D)		194,403	194,403	194,403	194,403	194,403	194,403	194,403	194,403	194,403	194,403	194,403	194,403	2,332,836
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		445,135	443,773	442,412	441,050	439,688	438,326	436,965	435,604	434,242	432,880	431,519	430,157	5,251,751
	a. Recoverable Costs Allocated to Energy		445,135	443,773	442,412	441,050	439,688	438,326	436,965	435,604	434,242	432,880	431,519	430,157	5,251,751
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		445,135	443,773	442,412	441,050	439,688	438,326	436,965	435,604	434,242	432,880	431,519	430,157	5,251,751
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$445,135	$443,773	$442,412	$441,050	$439,688	$438,326	$436,965	$435,604	$434,242	$432,880	$431,519	$430,157	$5,251,751

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.54 ($16,857,250), 312.54 ($38,069,546), 315.54 ($10,642,027), 316.54 ($687,934), 315.40 ($558,103).
(B) Line 6 x 6.7699% x 1/12. Based on ROE of 10.75% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 2.4%, 3.8%, 3.9%, 3.3%, 3.7%, and 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD System Reliability
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	
3.	Less: Accumulated Depreciation	(7,072,849)	(7,124,431)	(7,176,013)	(7,227,595)	(7,279,177)	(7,330,759)	(7,382,341)	(7,433,923)	(7,485,505)	(7,537,087)	(7,588,669)	(7,640,251)	(7,691,833)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$17,394,957	17,343,375	17,291,793	17,240,211	17,188,629	17,137,047	17,085,465	17,033,883	16,982,301	16,930,719	16,879,137	16,827,555	16,775,973	
6.	Average Net Investment		17,369,166	17,317,584	17,266,002	17,214,420	17,162,838	17,111,256	17,059,674	17,008,092	16,956,510	16,904,928	16,853,346	16,801,764	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$97,990	$97,699	$97,408	$97,117	$96,826	$96,535	$96,244	$95,953	$95,662	$95,371	$95,080	$94,789	$1,156,674
	b. Debt Component Grossed Up For Taxes (C)		23,670	23,600	23,529	23,459	23,389	23,318	23,248	23,178	23,107	23,037	22,967	22,897	279,399
8.	Investment Expenses														
	a. Depreciation (D)		51,582	51,582	51,582	51,582	51,582	51,582	51,582	51,582	51,582	51,582	51,582	51,582	618,984
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		173,242	172,881	172,519	172,158	171,797	171,435	171,074	170,713	170,351	169,990	169,629	169,268	2,055,057
	a. Recoverable Costs Allocated to Energy		173,242	172,881	172,519	172,158	171,797	171,435	171,074	170,713	170,351	169,990	169,629	169,268	2,055,057
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		173,242	172,881	172,519	172,158	171,797	171,435	171,074	170,713	170,351	169,990	169,629	169,268	2,055,057
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$173,242	$172,881	$172,519	$172,158	$171,797	$171,435	$171,074	$170,713	$170,351	$169,990	$169,629	$169,268	$2,055,057

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.45 ($23,011,597) and 312.44 ($1,456,209).
(B) Line 6 x 6.7699% x 1/12. Based on ROE of 10.75% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 2.5% and 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Mercury Air Toxics Standards (MATS)
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$8,635,028	$8,635,028	$8,635,028	$8,635,028	$8,635,028	$8,635,028	$8,635,028	$8,635,028	$8,635,028	$8,635,028	$8,635,028	$8,635,028	$8,635,028	
3.	Less: Accumulated Depreciation	(2,223,006)	(2,245,341)	(2,267,676)	(2,290,011)	(2,312,346)	(2,334,681)	(2,357,016)	(2,379,351)	(2,401,686)	(2,424,021)	(2,446,356)	(2,468,691)	(2,491,026)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$6,412,022	6,389,687	6,367,352	6,345,017	6,322,682	6,300,347	6,278,012	6,255,677	6,233,342	6,211,007	6,188,672	6,166,337	6,144,002	
6.	Average Net Investment		6,400,854	6,378,519	6,356,184	6,333,849	6,311,514	6,289,179	6,266,844	6,244,509	6,222,174	6,199,839	6,177,504	6,155,169	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$36,111	$35,985	$35,859	$35,733	$35,607	$35,481	$35,355	$35,229	$35,103	$34,977	$34,851	$34,725	$425,016
	b. Debt Component Grossed Up For Taxes (C)		8,723	8,692	8,662	8,631	8,601	8,571	8,540	8,510	8,479	8,449	8,418	8,388	102,664
8.	Investment Expenses														
	a. Depreciation (D)		22,335	22,335	22,335	22,335	22,335	22,335	22,335	22,335	22,335	22,335	22,335	22,335	268,020
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		67,169	67,012	66,856	66,699	66,543	66,387	66,230	66,074	65,917	65,761	65,604	65,448	795,700
	a. Recoverable Costs Allocated to Energy		67,169	67,012	66,856	66,699	66,543	66,387	66,230	66,074	65,917	65,761	65,604	65,448	795,700
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		67,169	67,012	66,856	66,699	66,543	66,387	66,230	66,074	65,917	65,761	65,604	65,448	795,700
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$67,169	$67,012	$66,856	$66,699	$66,543	$66,387	$66,230	$66,074	$65,917	$65,761	$65,604	$65,448	$795,700

Notes:

(A) Applicable depreciable base for Big Bend and Polk; accounts 312.44 ($3,427,481), 341.80 ($26,150), 315.40 ($1,226,949), 315.41 ($138,853), 315.42 ($138,853), 312.45 ($2,053,017), 312.46 ($1,242,315), 315.44 ($16,035), 315.45 ($40,217), 315.46 ($50,784), 311.40 ($13,216), 345.81 ($2,232), 312.54 ($210,295), 312.40 ($13,614), and 395.00 ($35,018).
(B) Line 6 x 6.7699% x 1/12. Based on ROE of 10.75% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 3.0%, 2.2%, 3.7%, 3.5%, 3.3%, 2.5%, 3.3%, 3.2%, 3.1%, 3.5%, 2.9%, 3.3%, 3.8%, 3.4%, and 14.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

For Project: SO_2 Emissions Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Purchases/Transfers		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Working Capital Balance														0
	a. FERC 158.1 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
	b. FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c. FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d. FERC 254.01 Regulatory Liabilities - Gains	(34,201)	(34,189)	(34,189)	(34,189)	(34,177)	(34,177)	(34,177)	(34,164)	(34,164)	(34,164)	(34,152)	(34,152)	(34,152)	
3.	Total Working Capital Balance	($34,201)	(34,189)	(34,189)	(34,189)	(34,177)	(34,177)	(34,177)	(34,164)	(34,164)	(34,164)	(34,152)	(34,152)	(34,152)	
4.	Average Net Working Capital Balance		($34,195)	($34,189)	($34,189)	($34,183)	($34,177)	($34,177)	($34,171)	($34,164)	($34,164)	($34,158)	($34,152)	($34,152)	
5.	Return on Average Net Working Capital Balance														
	a. Equity Component Grossed Up For Taxes (A)		($193)	($193)	($193)	($193)	($193)	($193)	($193)	($193)	($193)	($193)	($193)	($193)	(2,316)
	b. Debt Component Grossed Up For Taxes (B)		(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(564)
6.	Total Return Component		(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(2,880)
7.	Expenses:														
	a. Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. SO_2 Allowance Expense		(5)	7	7	(5)	7	7	(5)	7	7	(5)	7	7	41
8.	Net Expenses (D)		(5)	7	7	(5)	7	7	(5)	7	7	(5)	7	7	41
9.	Total System Recoverable Expenses (Lines 6 + 8)		(245)	(233)	(233)	(245)	(233)	(233)	(245)	(233)	(233)	(245)	(233)	(233)	(2,839)
	a. Recoverable Costs Allocated to Energy		(245)	(233)	(233)	(245)	(233)	(233)	(245)	(233)	(233)	(245)	(233)	(233)	(2,839)
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		(245)	(233)	(233)	(245)	(233)	(233)	(245)	(233)	(233)	(245)	(233)	(233)	(2,844)
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Juris. Recoverable Costs (Lines 12 + 13)		($245)	($233)	($233)	($245)	($233)	($233)	($245)	($233)	($233)	($245)	($233)	($233)	($2,844)

Notes:
(A) Line 6 x 6.7699% x 1/12. Based on ROE of 10.75% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(B) Line 6 x 1.6353% x 1/12
(C) Line 6 is reported on Schedule 7E.
(D) Line 8 is reported on Schedule 5E.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Gypsum Storage Facility
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	
3.	Less: Accumulated Depreciation	(4,399,971)	(4,451,850)	(4,503,729)	(4,555,608)	(4,607,487)	(4,659,366)	(4,711,245)	(4,763,124)	(4,815,003)	(4,866,882)	(4,918,761)	(4,970,640)	(5,022,519)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$17,067,388	17,015,509	16,963,630	16,911,751	16,859,872	16,807,993	16,756,114	16,704,235	16,652,356	16,600,477	16,548,598	16,496,719	16,444,840	
6.	Average Net Investment		17,041,449	16,989,570	16,937,691	16,885,812	16,833,933	16,782,054	16,730,175	16,678,296	16,626,417	16,574,538	16,522,659	16,470,780	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$96,141	$95,848	$95,555	$95,263	$94,970	$94,677	$94,385	$94,092	$93,799	$93,507	$93,214	$92,921	$1,134,372
	b. Debt Component Grossed Up For Taxes (C)		23,223	23,153	23,082	23,011	22,940	22,870	22,799	22,728	22,658	22,587	22,516	22,446	274,013
8.	Investment Expenses														
	a. Depreciation (D)		51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	622,548
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		171,243	170,880	170,516	170,153	169,789	169,426	169,063	168,699	168,336	167,973	167,609	167,246	2,030,933
	a. Recoverable Costs Allocated to Energy		171,243	170,880	170,516	170,153	169,789	169,426	169,063	168,699	168,336	167,973	167,609	167,246	2,030,933
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		171,243	170,880	170,516	170,153	169,789	169,426	169,063	168,699	168,336	167,973	167,609	167,246	2,030,933
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$171,243	$170,880	$170,516	$170,153	$169,789	$169,426	$169,063	$168,699	$168,336	$167,973	$167,609	$167,246	$2,030,933

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.40
(B) Line 6 x 6.7699% x 1/12. Based on ROE of 10.75% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 2.9%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Coal Combustion Residual Rule (CCR Rule)
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$250,000	$250,000	$250,000	$750,000	$0	$0	$0	$0	$0	$0	$0	$0	$1,500,000
	b. Clearings to Plant		250,000	250,000	250,000	750,000	0	0	0	0	0	0	0	0	1,500,000
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$3,903,531	$4,153,531	$4,403,531	$4,653,531	$5,403,531	$5,403,531	$5,403,531	$5,403,531	$5,403,531	$5,403,531	$5,403,531	$5,403,531	$5,403,531	
3.	Less: Accumulated Depreciation	(117,761)	(128,489)	(139,925)	(152,070)	(164,923)	(179,901)	(194,879)	(209,857)	(224,835)	(239,813)	(254,791)	(269,769)	(284,747)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$3,785,770	4,025,042	4,263,606	4,501,461	5,238,608	5,223,630	5,208,652	5,193,674	5,178,696	5,163,718	5,148,740	5,133,762	5,118,784	
6.	Average Net Investment		3,905,406	4,144,324	4,382,534	4,870,035	5,231,119	5,216,141	5,201,163	5,186,185	5,171,207	5,156,229	5,141,251	5,126,273	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$22,033	$23,381	$24,724	$27,475	$29,512	$29,427	$29,343	$29,258	$29,174	$29,089	$29,005	$28,920	$331,341
	b. Debt Component Grossed Up For Taxes (C)		5,322	5,648	5,972	6,637	7,129	7,108	7,088	7,067	7,047	7,027	7,006	6,986	80,037
8.	Investment Expenses														
	a. Depreciation (D)		10,728	11,436	12,145	12,853	14,978	14,978	14,978	14,978	14,978	14,978	14,978	14,978	166,986
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		38,083	40,465	42,841	46,965	51,619	51,513	51,409	51,303	51,199	51,094	50,989	50,884	578,364
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		38,083	40,465	42,841	46,965	51,619	51,513	51,409	51,303	51,199	51,094	50,989	50,884	578,364
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		38,083	40,465	42,841	46,965	51,619	51,513	51,409	51,303	51,199	51,094	50,989	50,884	578,364
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$38,083	$40,465	$42,841	$46,965	$51,619	$51,513	$51,409	$51,303	$51,199	$51,094	$50,989	$50,884	$578,364

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.40 ($261,568), 312.44 ($668,735) and 312.40 ($4,473,228).
(B) Line 6 x 6.7699% x 1/12. Based on ROE of 10.75% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 2.9%, 3.0% and 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Coal Combustion Residuals (CCR Rule - Phase II)
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$2,009,031	$2,009,031	$2,009,031	$2,009,031	$2,009,031	$2,009,031	$2,009,031	$2,009,031	$2,009,031	$2,009,031	$2,009,031	$2,009,031	$2,009,031	
3.	Less: Accumulated Depreciation	(10,046)	(15,069)	(20,092)	(25,115)	(30,138)	(35,161)	(40,184)	(45,207)	(50,230)	(55,253)	(60,276)	(65,299)	(70,322)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,998,985	1,993,962	1,988,939	1,983,916	1,978,893	1,973,870	1,968,847	1,963,824	1,958,801	1,953,778	1,948,755	1,943,732	1,938,709	
6.	Average Net Investment		1,996,474	1,991,451	1,986,428	1,981,405	1,976,382	1,971,359	1,966,336	1,961,313	1,956,290	1,951,267	1,946,244	1,941,221	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$11,263	$11,235	$11,207	$11,178	$11,150	$11,122	$11,093	$11,065	$11,037	$11,008	$10,980	$10,952	$133,290
	b. Debt Component Grossed Up For Taxes (C)		2,721	2,714	2,707	2,700	2,693	2,686	2,680	2,673	2,666	2,659	2,652	2,645	32,196
8.	Investment Expenses														
	a. Depreciation (D)		5,023	5,023	5,023	5,023	5,023	5,023	5,023	5,023	5,023	5,023	5,023	5,023	60,276
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		19,007	18,972	18,937	18,901	18,866	18,831	18,796	18,761	18,726	18,690	18,655	18,620	225,762
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		19,007	18,972	18,937	18,901	18,866	18,831	18,796	18,761	18,726	18,690	18,655	18,620	225,762
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		19,007	18,972	18,937	18,901	18,866	18,831	18,796	18,761	18,726	18,690	18,655	18,620	225,762
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$19,007	$18,972	$18,937	$18,901	$18,866	$18,831	$18,796	$18,761	$18,726	$18,690	$18,655	$18,620	$225,762

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.44.
(B) Line 6 x 6.7699% x 1/12. Based on ROE of 10.75% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate 3.0%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend ELG Compliance
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$1,685,199	$1,635,199	$1,135,199	$1,065,199	$1,385,199	$735,199	$785,199	$2,480,199	$1,315,199	$415,199	$335,199	$538,245	$13,510,436
	b. Clearings to Plant		0	0	0	0	20,137,642	735,199	785,199	2,480,199	1,315,199	415,199	335,199	538,245	26,742,082
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$0	$0	$0	$0	$0	$20,137,642	$20,872,842	$21,658,041	$24,138,240	$25,453,439	$25,868,639	$26,203,838	$26,742,082	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	(57,057)	(116,197)	(177,561)	(245,953)	(318,071)	(391,365)	(465,609)	
4.	CWIP - Non-Interest Bearing	13,231,646	14,916,846	16,552,045	17,687,244	18,752,443	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$13,231,646	14,916,846	16,552,045	17,687,244	18,752,443	20,137,642	20,815,785	21,541,844	23,960,679	25,207,486	25,550,568	25,812,473	26,276,473	
6.	Average Net Investment		14,074,246	15,734,445	17,119,644	18,219,844	19,445,043	20,476,714	21,178,814	22,751,261	24,584,083	25,379,027	25,681,520	26,044,473	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$79,401	$88,767	$96,582	$102,789	$109,701	$115,521	$119,482	$128,353	$138,693	$143,178	$144,884	$146,932	$1,414,283
	b. Debt Component Grossed Up For Taxes (C)		19,180	21,442	23,330	24,829	26,499	27,905	28,861	31,004	33,502	34,585	34,997	35,492	341,626
8.	Investment Expenses														
	a. Depreciation (D)		0	0	0	0	0	57,057	59,140	61,364	68,392	72,118	73,294	74,244	465,609
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		98,581	110,209	119,912	127,618	136,200	200,483	207,483	220,721	240,587	249,881	253,175	256,668	2,221,518
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		98,581	110,209	119,912	127,618	136,200	200,483	207,483	220,721	240,587	249,881	253,175	256,668	2,221,518
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		98,581	110,209	119,912	127,618	136,200	200,483	207,483	220,721	240,587	249,881	253,175	256,668	2,221,518
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$98,581	$110,209	$119,912	$127,618	$136,200	$200,483	$207,483	$220,721	$240,587	$249,881	$253,175	$256,668	$2,221,518

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.40
(B) Line 6 x 6.7699% x 1/12. Based on ROE of 10.75% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 3.4%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Section 316(b) Impingement Mortality
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$483,000	$350,572	$331,138	$398,007	$134,000	$4,000	$4,000	$657	$0	$0	$0	$0	$1,705,374
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	12,871,825	13,354,825	13,705,397	14,036,535	14,434,542	14,568,542	14,572,542	14,576,542	14,577,199	14,577,199	14,577,199	14,577,199	14,577,199	
5.	Net Investment (Lines 2 + 3 + 4)	$12,871,825	13,354,825	13,705,397	14,036,535	14,434,542	14,568,542	14,572,542	14,576,542	14,577,199	14,577,199	14,577,199	14,577,199	14,577,199	
6.	Average Net Investment		13,113,325	13,530,111	13,870,966	14,235,539	14,501,542	14,570,542	14,574,542	14,576,871	14,577,199	14,577,199	14,577,199	14,577,199	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$73,980	$76,331	$78,254	$80,311	$81,812	$82,201	$82,223	$82,237	$82,238	$82,238	$82,238	$82,238	$966,301
	b. Debt Component Grossed Up For Taxes (C)		17,870	18,438	18,903	19,399	19,762	19,856	19,861	19,865	19,865	19,865	19,865	19,865	233,414
8.	Investment Expenses														
	a. Depreciation (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		91,850	94,769	97,157	99,710	101,574	102,057	102,084	102,102	102,103	102,103	102,103	102,103	1,199,715
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		91,850	94,769	97,157	99,710	101,574	102,057	102,084	102,102	102,103	102,103	102,103	102,103	1,199,715
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		91,850	94,769	97,157	99,710	101,574	102,057	102,084	102,102	102,103	102,103	102,103	102,103	1,199,715
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$91,850	$94,769	$97,157	$99,710	$101,574	$102,057	$102,084	$102,102	$102,103	$102,103	$102,103	$102,103	$1,199,715

Notes:
(A) Applicable depreciable base for Big Bend; accounts TBD depending on type of plant added
(B) Line 6 x 6.7699% x 1/12. Based on ROE of 10.75% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is TBD depending on type of plant added
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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ECRC 2022 PROJECTION, FORM 42-4P
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Tampa Electric Company
Environmental Cost Recovery Clause
January 2022 through December 2022
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 3 Flue Gas Desulfurization Integration

Project Description:

This project involved the integration of Big Bend Unit 3 flue gases into the Big Bend Unit 4 Flue Gas Desulfurization ("FGD") system. The integration was accomplished by installing interconnecting ductwork between Unit 3 precipitator outlet ducts and the Unit 4 FGD inlet duct. The Unit 4 FGD outlet duct was interconnected with the Unit 3 chimney via new ductwork and a new stack breaching. New ductwork, linings, isolation dampers, support steel, and stack annulus pressurization fans were procured and installed. Modifications to the materials handling systems and controls were also necessary.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021, is $903,783 compared to the original projection of $906,095.

The actual/estimated O&M expense for the period January 2021 through December 2021 is $0 and did not vary from the original projection.

Progress Summary: This project was approved by the Commission in Docket No. 19960688-EI, Order No. PSC-1996-1048-FOF-EI, issued August 14, 1996. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $914,729.

There are not any projected O&M costs for the period January 2022 through December 2022.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2022 through December 2022
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Units 1 & 2 Flue Gas Conditioning

Project Description:

The existing electrostatic precipitators were not designed for the range of fuels needed for compliance with the Clean Air Act Amendments ("CAAA"). Flue gas conditioning was required to assure operation of the generating units in accordance with applicable permits and regulations. This equipment is still required to ensure compliance with the CAAA in the event the FGD system on Units 1 & 2 is not operating.

The project involved the addition of molten sulfur unloading, storage and conveying to sulfur burners and catalytic converters where SO_2 is converted to SO_3. The control and injection system then injects this into the ductwork ahead of the electrostatic precipitators.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $192,990 compared to the original projection of $193,042.

The actual/estimated O&M expense for the period January 2021 through December 2021 is $0 and did not vary from the original projection.

Progress Summary: This project was approved by the Commission in Docket No. 19960688-EI, Order No. PSC-1996-1048-FOF-EI, issued August 14, 1996. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $79,937.

There are not any O&M costs projected for the period of January 2022 through December 2022.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2022 through December 2022
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 4 Continuous Emissions Monitors

Project Description:

Continuous emissions monitors ("CEMs") were installed on the flue gas inlet and outlet of Big Bend Unit 4 to monitor compliance with the CAAA requirements. The monitors are capable of measuring, recording and electronically reporting SO_2, NO_x and volumetric gas flow out of the stack. The project consisted of monitors, a CEM building, the CEMs control and power cables to supply a complete system.

40 CFR Part 75 includes the general requirements for the installation, certification, operation, and maintenance of CEMs and specific requirements for the monitoring of pollutants, opacity, and volumetric flow. These regulations are very comprehensive and specific as to the requirements for CEMs, and in essence, they define the components needed and their configuration.

Project Accomplishment:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $45,522 compared to the original projection of $45,598.

Progress Summary: This project was approved by the Commission in Docket No. 19960688-EI, Order No. PSC-1996-1048-FOF-EI, issued August 14, 1996. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $44,473.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2022 through December 2022
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 1 Classifier Replacement

Project Description:

The boiler modifications at Big Bend Unit 1 are part of Tampa Electric's NO_X compliance strategy for Phase II of the CAAA. The classifier replacements optimize coal fineness by providing a uniform particle size. This finer classification, combined with the equalized distribution of coal to outlet pipes and furnaces, enables a uniform, staged combustion. As a result, firing systems operate at lower NO_X levels.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $69,128 compared to the original projection of $69,201.

Progress Summary: This project was approved by the Commission in Docket No. 19980007-EI, Order No. PSC-1998-1764-FOF-EI, issued December 31, 1998. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $ 65,893.

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Project Title: Big Bend Unit 2 Classifier Replacement

Project Description:

The boiler modifications at Big Bend Unit 2 are part of Tampa Electric's NO_X compliance strategy for Phase II of the CAAA. The classifier replacements optimize coal fineness by providing a more uniform particle size. This finer classification, combined with the equalized distribution of coal to outlet pipes and furnaces, enables a uniform, staged combustion. As a result, firing systems operate at lower NO_X levels.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $50,424 compared to the original projection of $50,482.

Progress Summary: This project was approved by the Commission in Docket No. 19980007-EI, Order No. PSC-1998-1764-FOF-EI, issued December 31, 1998. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $48,366.

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Project Title: Big Bend Units 1 & 2 FGD

Project Description:

The Big Bend Units 1 & 2 FGD system consists of equipment capable of removing SO_2 from the flue gas generated by the combustion of coal. The FGD was installed in order to comply with Phase II of the CAAA. Compliance with Phase II was required by January 1, 2000. The CAAA impose SO_2 emission limits on existing steam electric units with an output capacity of greater than 25 megawatts and all new utility units. Tampa Electric conducted an exhaustive analysis of options to comply with Phase II of the CAAA that culminated in the selection of the FGD project to serve Big Bend Units 1 & 2.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $5,431,446 compared to the original projection of $5,440,931.

The actual/estimated O&M costs for the period January 2021 through December 2021 are $8,966 compared to the original estimate of $0, resulting in a variance of 100 percent. The variance is due to Big Bend Unit 2 operating the FGD system when generating by natural gas which was not originally anticipated but is required for cooling gases to protect system ductwork.

Progress Summary: This project was approved by the Commission in Docket No. 19980693-EI, Order No. PSC-1999-0075-FOF-EI, issued January 11, 1999. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $5,331,524.

There are not any O&M costs projected for the period January 2022 through December 2022.

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Project Title: Big Bend Section 114 Mercury Testing Platform

Project Description:

The Mercury Emissions Information Collection Effort is mandated by the EPA. The EPA asserts that Section 114 of the CAAA grants EPA the authority to request the collection of information necessary for it to study whether it is appropriate and necessary to develop performance of emission standards for electric utility steam generating units.

In a letter dated November 25, 1998, Tampa Electric was notified by the EPA that, pursuant to Section 114 of the CAAA, the company was required to periodically sample and analyze coal shipments for mercury and chlorine content during the period January 1, 1999 through December 31, 1999.

In addition to coal sampling, stack testing and analyses are also required. Tampa Electric received a second letter from EPA, dated March 11, 1999, requiring Tampa Electric to perform specialized mercury testing of the inlet and outlet of the last emission control device installed for Big Bend Units 1, 2 or 3, and Polk Unit 1 as part of the mercury data collection. Part of the cost incurred to perform the stack testing is due to the need to construct special test facilities at the Big Bend stack testing location to meet EPA's testing requirements.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $7,943 compared to the original projection of $7,958.

Progress Summary: This project was approved by the Commission in Docket No. 19990976-EI, Order No. PSC-1999-2103-PAA-EI, issued October 25, 1999. The project was placed in service in December 1999 and completed in May 2000.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $7,964.

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Project Title: Big Bend FGD Optimization and Utilization

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to optimize the SO_2 removal efficiency and operations of the Big Bend Units 1, 2 and 3 FGD systems. Tampa Electric performed activities in three key areas to improve the performance and reliability of the Big Bend Units 1, 2 and 3 FGD systems. The majority of the improvements required on the Unit 3 tower module included the tower piping, nozzle and internal improvements, ductwork improvements, electrical system reliability improvements, tower control improvements, dibasic acid system improvements, booster fan reliability, absorber system improvements, quencher system improvements, and tower demister improvements. Big Bend Units 1 and 2 FGD system improvements included additional preventative maintenance, oxidation air control improvements, and tower water, air reagent and start-up piping upgrades. In order to ensure reliability of the FGD systems, improvements to the common limestone supply, gypsum de-watering stack reliability and wastewater treatment plant were also performed.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $1,503,371 compared to the original projection of $1,507,233.

Progress Summary: This project was approved by the Commission in Docket No. 20000685-EI, Order No. PSC-2000-1906-PAA-EI, issued October 18, 2000. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $1,522,184.

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Project Title: Big Bend PM Minimization and Monitoring

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to develop a Best Operational Practices ("BOP") study to minimize emissions from each electrostatic precipitator ("ESP") at Big Bend, as well as perform a best available control technology ("BACT") analysis for the upgrade of each existing ESP. The company is also required to install and operate particulate matter continuous emission monitors on Big Bend Units 1, 2 and 3 FGD systems. Tampa Electric identified improvements that were necessary to optimize ESP performance such as modifications to the turning vanes and precipitator distribution plates, and upgrades to the controls and software system of the precipitators. Tampa Electric incurred costs associated with the recommendations of the BOP study and the BACT analysis in 2001 and continues to make O&M and capital expenditures.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $1,680,736 compared to the original projection of $1,684,675.

The actual/estimated O&M costs for the period January 2021 through December 2021 are $218,747 compared to the original projection of $252,000, resulting in a variance of -13.2 percent. This variance is due to Big Bend Units operating less than projected. As a result, less maintenance is required.

Progress Summary: This project was approved by the Commission in Docket No. 20001186-EI, Order No. PSC-2000-2104-PAA-EI, issued November 6, 2000. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $1,687,549.

The estimated O&M costs for the period January 2022 through December 2022 are $259,560.

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Project Title: Big Bend NO_x Emissions Reduction

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to spend up to $3 million with the goal to reduce NO_x emissions at Big Bend Station. By 2002, the Consent Decree required the company to achieve at least a 30 percent reduction beyond 1998 NO_x emission levels for Big Bend Units 1 and 2 and at least a 15 percent reduction in NO_x emissions from Big Bend Unit 3. Tampa Electric identified and completed projects that were the first steps to decrease NO_x emissions in these units such as burner and windbox modifications and the installation of a neural network system on each of the Big Bend units.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $485,706 compared to the original projection of $487,214.

The actual/estimated O&M costs for the period January 2021 through December 2021 are $2,950 compared to the original projection of $2,028, resulting in a variance of 45.5 percent. This variance is due to maintenance required on a secondary damper that was more than originally projected.

Progress Summary: This project was approved by the Commission in Docket No. 20001186-EI, Order No. PSC-2000-2104-PAA-EI, issued November 6, 2000. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $501,526.

The estimated O&M costs projected for the period January 2022 through December 2022 are $2,089.

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Project Title: Big Bend Fuel Oil Tank No. 1 Upgrade

Project Description:

The Big Bend Fuel Oil Tank No. 1 Upgrade is a 500,000 gallon field-erected fuel storage tank that is required to meet the requirements of FDEP Rule 62-762 as an existing field-erected above ground storage tank containing a regulated pollutant (diesel fuel). The rule required various modifications and a complete internal inspection by the end of 1999.

The scope of work for this project included cleaning and inspecting the tank in accordance with API 653 specifications, coating the internal floor plus 30 inches up the tank wall, installing an AEI Segundo bottom to the tank as well as installing a leak detection system, installing a spill containment for piping fittings and valves surrounding the tank, installing a new truck unloading facility and spill containment for the truck unloading facility, installing level instrumentation for overfill protection, installing secondary containment for below ground piping or reroute to above ground, and conducting a tank closure assessment.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $63,892 compared to the original projection of $63,896.

Progress Summary: This project was approved by the Commission in Docket No. 19980007-EI, Order No. PSC-1998-0408-FOF-EI, issued March 18, 1998. The project has been retired.

Projections: The investment was fully amortized in 2021. There is neither depreciation nor return for the period January 2022 through December 2022.

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Project Title: Big Bend Fuel Oil Tank No. 2 Upgrade

Project Description:

The Big Bend Fuel Oil Tank No. 2 is a 4,200,000 gallon field-erected fuel storage tank that is required to meet the requirements of FDEP Rule 62-762 as an existing field-erected above ground storage tank containing a regulated pollutant (diesel fuel). The rule required various modifications and a complete internal inspection by the end of 1999.

The scope of work for this project included cleaning and inspecting the tank in accordance with API 653 specifications, coating the internal floor plus 30 inches up the tank wall, installing an AEI Segundo bottom to the tank as well as installing a leak detection system, installing a spill containment for piping fittings and valves surrounding the tank, installing a new truck unloading facility and spill containment for the truck unloading facility, installing level instrumentation for overfill protection, installing secondary containment for below ground piping or reroute to above ground, and conducting a tank closure assessment.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $105,079 compared to the original projection of $105,098.

Progress Summary: This project was approved by the Commission in Docket No. 19980007-EI, Order No. PSC-1998-0408-FOF-EI, issued March 18, 1998. The project has been retired.

Projections: The investment was fully amortized in 2021. There is neither depreciation nor return for the period January 2022 through December 2022.

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Project Title: SO_2 Emission Allowances

Project Description:

The acid rain control title of the CAAA sets forth a comprehensive regulatory mechanism designed to control acid rain by limiting sulfur dioxide emissions by electric utilities. The CAAA requires reductions in SO_2 emissions in two phases. Phase I began on January 1, 1995 and applies to 110 mostly coal-fired utility plants containing about 260 generating units. These plants are owned by some 40 jurisdictional utility systems that are expected to reduce annual SO_2 emissions by as much as 4.5 million tons. Phase II began on January 1, 2000, and applies to virtually all existing steam-electric generating utility units with capacity exceeding 25 megawatts and to new generating utility units of any size. The EPA issues to the owners of generating units allowances (defined as an authorization to emit, during or after a specified calendar year, one ton of SO_2) equal to the number of tons of SO_2 emissions authorized by the CAAA. EPA does not assess a charge for the allowances it awards.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated return on average net working capital for the period January 2021 through December 2021 is ($2,688) compared to the original projection of ($2,688).

The actual/estimated O&M costs for the period January 2021 through December 2021 are $41 compared to the original projection of $15. The variance is not material.

Progress Summary: SO_2 emission allowances are being used by Tampa Electric to meet compliance standards for Phase I of the CAAA.

Project Projections: The estimated return on average net working capital for the period January 2022 through December 2022 is ($2,880).

The estimated O&M costs for the period January 2022 through December 2022 are $41.

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Project Title: National Pollutant Discharge Elimination System ("NPDES") Annual Surveillance Fees

Project Description:

Chapter 62-4.052, Florida Administrative Code ("F.A.C."), implements the annual regulatory program and surveillance fees for wastewater permits. These fees are in addition to the application fees described in Rule 62-4.050, F.A.C. Tampa Electric's Big Bend, Polk, and Bayside Stations are affected by this rule.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M costs for the period January 2021 through December 2021 is $34,500 compared to the original projection of $23,500. The variance is 46.8 percent and is due to Polk NPDES fees not being included in setting the original projection.

Progress Summary: NPDES Surveillance fees are paid annually for the prior year.

Projections: The estimated O&M costs for the period January 2022 through December 2022 are $34,500.

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Project Title: Gannon Thermal Discharge Study

Project Description:

This project was a direct requirement from the FDEP in conjunction with the renewal of Tampa Electric's Industrial Wastewater Facility Permit under the provisions of Chapter 403, Florida Statutes, and applicable rules of the Florida Administrative Code, which constitute authorization for the company's Gannon Station facility to discharge to waters of the State under the NPDES. The FDEP permit is Permit No. FL0000809. Specifically, Tampa Electric was required to perform a 316(a) determination for Gannon Station to ensure the protection and propagation of a balanced, indigenous population of shellfish, fish, and wildlife within the primary area of study. The project had two facets: 1) developing a plan of study and identified the thermal plume, and 2) implemented the plan of study through appropriate sampling to make the determination if any adverse impacts are occurring.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M expense for the period January 2021 through December 2021 is $0 and did not vary from the original projection.

Progress Summary: This project was approved by the Commission in Docket No. 20010593-EI, Order No. PSC-2001-1847-PAA-EI on September 4, 2001. The project is complete and in service.

Projections: There are not any O&M costs projected for the period January 2022 through December 2022.

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Project Title: Polk NO_x Emissions Reduction

Project Description:

This project was designed to meet a lower NO_x emissions limit established by the FDEP for Polk Unit 1 by July 1, 2005. The lower limit of 15 parts per million by volume dry basis at 15 percent O_2 is specified in FDEP Permit No. PSD-FL-194F issued February 5, 2002. The project consisted of two phases: 1) the humidification of syngas through the installation of a syngas saturator; and 2) the modification of controls and the installation of additional guide vanes to the diluent nitrogen compressor.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $103,219 compared to the original projection of $103,428.

The actual/estimated O&M costs for the period January 2021 through December 2021 is $595 compared to the original projection of $0. The variance is 100 percent and is due to costs being charged to the project work order in error. The amount will be reversed in July 2021.

Progress Summary: This project was approved by the Commission in Docket No. 20020726-EI, Order No. PSC-2002-1445-PAA-EI on October 21, 2002. The project is complete and in service.

Project Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $102,358.

There are not any O&M costs projected for the period of January 2022 through December 2022.

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Project Title: Bayside SCR Consumables

Project Description:

This project is necessary to achieve the NO_x emissions limit of 3.5 parts per million established by the FDEP Consent Final Judgment and the EPA Consent Decree for the natural gas-fired Bayside Power Station. To achieve this NO_x limit, the installation of selective catalytic reduction (SCR) systems is required. An SCR system requires consumable goods – primarily anhydrous ammonia – to be injected into the catalyst bed in order to achieve the required NO_x emissions limit. Principally, the project was designed to capture the cost of consumable goods necessary to operate the SCR systems.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M costs for the period January 2021 through December 2021 are $139,173 compared to the original projection of $119,000. The variance is 17 percent and is due to Bayside Station generation being greater than originally projected, leading to the need for more consumables.

Progress Summary: This project was approved by the Commission in Docket No. 20021255-EI, Order No. PSC-2003-0469-PAA-EI, issued April 4, 2003. Annual O&M expenses will continue to be incurred.

Projections: The estimated O&M costs for the period January 2022 through December 2022 are projected to be $151,000.

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Project Title: Big Bend Unit 4 Separated Overfire Air (“SOFA”)

Project Description:

This project is necessary to assist in achieving the NO_x emissions limit established by the FDEP Consent Final Judgment and the EPA Consent Decree for Big Bend Unit 4. A SOFA system stages secondary combustion air to prevent NO_x formation that would otherwise require removal by post-combustion technology. In-furnace combustion control through a SOFA system is the most cost-effective means to reduce NO_x emissions prior to the application of these technologies. Costs associated with the SOFA system entailed capital expenditures for equipment installation and subsequent annual maintenance.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $185,038 compared to the original projection of $185,486.

The actual/estimated O&M expense for the period January 2021 through December 2021 is $0 and did not vary from the original projection.

Progress Summary: This project was approved by the Commission in Docket No. 20030226-EI, Order No. PSC-2003-0684-PAA-EI, issued June 6, 2003. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $186,356.

There are not any O&M costs projected for the period of January 2022 through December 2022.

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Project Title: Big Bend Unit 1 Pre-SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2021 through 2022. Thus, the installation of cost-effective SCR technology on the generating units was necessary to meet NO_x emissions requirements. This project was a necessary precursor to an SCR system designed to reduce inlet NO_x concentrations to the SCR system thereby mitigating overall capital and O&M costs. The Big Bend Unit 1 Pre-SCR technologies included a neural network system, secondary air controls and windbox modifications.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $124,987 compared to the original projection of $125,229.

The actual/estimated O&M expense for the period January 2021 through December 2021 is $0 and did not vary from the original projection.

Progress Summary: This project was approved by the Commission in Docket No. 20040750-EI, Order No. PSC-2004-0986-CO-EI, issued October 11, 2004. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $123,675.

There are not any O&M costs projected for the period of January 2022 through December 2022.

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Project Title: Big Bend Unit 2 Pre-SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2021 through 2022. Thus, the installation of cost-effective SCR technology on the generating units was necessary to meet NO_x emissions requirements. This project was a necessary precursor to an SCR system designed to reduce inlet NO_x concentrations to the SCR system thereby mitigating overall capital and O&M costs. The Big Bend Unit 2 Pre-SCR technologies included secondary air controls and windbox modifications.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $119,909 compared to the original projection of $120,162.

The actual/estimated O&M expense for the period January 2021 through December 2021 is $0 and did not vary from the original projection.

Progress Summary: This project was approved by the Commission in Docket No. 20040750-EI, Order No. PSC-2004-0986-CO-EI, issued October 11, 2004. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $119,394.

There are not any O&M costs projected for the period of January 2022 through December 2022.

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Project Title: Big Bend Unit 3 Pre-SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2021 through 2022. Thus, the installation of cost-effective SCR technology on the generating units was necessary to meet NO_x emissions requirements. This project was a necessary precursor to an SCR system designed to reduce inlet NO_x concentrations to the SCR system thereby mitigating overall capital and O&M costs. The Big Bend Unit 3 Pre-SCR technologies included a neutral network system, secondary air controls, windbox modifications and primary coal/air flow controls.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $216,230 compared to the original projection of $216,730.

The actual/estimated O&M expense for the period January 2021 through December 2021 is $0 and did not vary from the original projection.

Progress Summary: This project was approved by the Commission in Docket No. 20040750-EI, Order No. PSC-2004-0986-CO-EI, issued October 11, 2004. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $216,878.

There are not any O&M costs projected for the period of January 2022 through December 2022.

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Project Title: Clean Water Act Section 316(b) Phase II Study

Project Description:

This project was a direct requirement from the EPA to reduce impingement and entrainment of aquatic organisms related to the withdrawal of waters for cooling purposes through cooling water intake structures. The Phase II Rule requires that power plants meet certain criteria to comply with national performance standards for impingement and entrainment. Accordingly, Tampa Electric must develop its compliance strategies for its Bayside and Big Bend Stations and then submit these strategies for approval through a Comprehensive Demonstration Study to the FDEP.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M costs for the period January 2021 through December 2021 are $6,020 compared to the original projection of $45,000, resulting in a variance of -86.6 percent. This variance is due to the delay in receiving the NPDES permit. Once the permit is received, the costs will be incurred.

Progress Summary: This project was approved by the Commission in Docket No. 20041300-EI, Order No. PSC-2005-0164-PAA-EI, issued February 10, 2005.

Projections: The estimated O&M costs for the period January 2022 through December 2022 are $10,150.

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Project Title: Big Bend Unit 1 SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times. The installation of cost-effective SCR technology on the generating units was necessary to meet NO_x emissions requirements.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $7,151,546 compared to the original projection of $7,165,809.

The actual/estimated O&M expense for the period January 2021 through December 2021 is $0 and did not vary from the original projection.

Progress Summary: This project was approved by the Commission in Docket No. 20041376-EI, Order No. PSC-2005-0502-CO-EI, issued May 9, 2005. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $7,086,740.

There are not any O&M costs projected for the period January 2022 through December 2022.

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Project Title: Big Bend Unit 2 SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times. The installation of cost-effective SCR technology on the generating units was necessary to meet NO_x emissions requirements.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $7,876,719 compared to the original projection of $7,893,828.

The actual/estimated O&M costs for the period January 2021 through December 2021 are $106,340 compared to the original projection of $122,020, resulting in a variance of -12.9 percent. This variance is due to current estimates of Big Bend Unit 2 SCR maintenance costs, while generating on natural gas, are expected to be lower than originally projected, along with less total generation than originally estimated.

Progress Summary: This project was approved by the Commission in Docket No. 20041376-EI, Order No. PSC-2005-0502-CO-EI, issued May 9, 2005. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $7,857,960.

There are not any O&M costs projected for the period January 2022 through December 2022.

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Project Title: Big Bend Unit 3 SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times. The installation of cost-effective SCR technology on the generating units was necessary to meet NO_x emissions requirements.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $6,415,803 compared to the original projection of $6,429,857.

The actual/estimated O&M costs for the period January 2021 through December 2021 are $542,672 compared to the original projection of $524,097, resulting in a variance of 3.5 percent.

Progress Summary: This project was approved by the Commission in Docket No. 20041376-EI, Order No. PSC-2005-0502-CO-EI, issued May 9, 2005. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $6,404,948.

The estimated O&M costs for the period January 2022 through December 2022 are $372,522.

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Project Title: Big Bend Unit 4 SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times. The installation of cost-effective SCR technology on the generating units was necessary to meet NO_x emissions requirements.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $5,168,642 compared to the original projection of $5,199,976.

The actual/estimated O&M costs for the period January 2021 through December 2021 are $893,479 compared to the original projection of $1,077,230, resulting in a variance of -17.1 percent. This variance is due to current estimates of Big Bend Unit 4 SCR maintenance costs, while generating on natural gas, are expected to be lower than originally projected, along with less total generation than originally projected.

Progress Summary: This project was approved by the Commission in Docket No. 20040750-EI, Order No. PSC-2004-0986-PAA-EI, issued October 11, 2004. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $5,251,751.

The estimated O&M costs for the period January 2022 through December 2022 are $1,397,376.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2022 through December 2022
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Arsenic Groundwater Standard Program

Project Description:
The Arsenic Groundwater Standard Program that is required by the Environmental Protection Agency and the Department of Environmental Protection became effective January 1, 2005. It requires regulated entities of the State of Florida to monitor the drinking water and groundwater Maximum Contaminant Level ("MCL") for arsenic under the federal rule known as the Safe Drinking Water Act.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M costs for the period January 2021 through December 2021 are $0 compared to the original projection of $36,000. This variance is due to the delay of groundwater monitoring work while awaiting Florida Department of Environmental Protection ("FDEP") approval of the company's plan. Once the permit is received, the costs will be incurred.

Progress Summary: This project was approved by the Commission in Docket No. 20050683-EI, Order No. PSC-2006-0138-PAA-EI, issued February 23, 2006. The project is complete and in service.

Projections: The estimated O&M costs for the period of January 2022 through December 2022 are $37,080.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2022 through December 2022
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Flue Gas Desulfurization ("FGD") System Reliability

Project Description:
The Big Bend FGD Reliability project is necessary to maintain the FGD system operations that are required by the Consent Decree. Tampa Electric is required to operate the FGD systems at Big Bend Station whenever coal is combusted in the units with few exceptions. The compliance dates for the strictest operational characteristics were January 1, 2011 for Big Bend Unit 3 and January 1, 2014 for Big Bend Units 1 and 2.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $2,007,420 compared to the original projection of $2,013,174.

Progress Summary: This project was approved by the Commission in Docket No. 20050598-EI, Order No. PSC-2006-0602-PAA-EI, issued July 10, 2006. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $2,055,057.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2022 through December 2022
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Mercury Air Toxics Standards ("MATS")

Project Description:
In March 2005, the Environmental Protection Agency ("EPA") promulgated the Clean Air Mercury Rule ("CAMR") and was later challenged in court. On February 8, 2008, the Circuit Court of Appeals for the District of Columbia vacated CAMR and ordered a new rule by March 2011. On December 11, 2011, the EPA issued a final version of the rule that applies to all coal and oil-fired electric generating units with a capacity of 25 MW or more and with a compliance deadline is April 16, 2015. The rule sets forth hazardous air pollutant standards ("HAP") for mercury, non-mercury metal HAPs and acid gasses.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $781,102 compared to the original projection of $783,036.

The actual/estimated O&M costs for the period January 2021 through December 2021 are $5,494 compared to the original projection of $3,000, resulting in a variance of 83.1 percent. This variance is due to higher cost of mercury traps used for stack testing than originally projected.

Progress Summary: This project was approved by the Commission in Docket No. 20120302-EI, Order No. PSC-2013-0191-PAA-EI, issued May 6, 2013. The project is in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is projected to be $795,700.

The estimated O&M costs for the period January 2022 through December 2022 are projected to be $2,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2022 through December 2022
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Greenhouse Gas Reduction Program

Project Description:
On September 22, 2009, the EPA enacted a new rule for reporting Greenhouse Gas ("GHG") emissions from large sources and suppliers effective January 1, 2010 in preparation for the first annual GHG report, due March 31, 2011. The new rule is intended to collect accurate and timely emissions data to inform future policy decisions as set forth in the final rule for GHG emission reporting pursuant to the Florida Climate Protection Act, Chapter 403.44 of the Florida Statutes and the docket EPA-HQ-OAR2008-0508-054. The nationwide GHG emissions reduction rule will impact Tampa Electric's generation fleet, components of its transmission and distribution system as well as company service vehicles. According to the rule, the company began collecting greenhouse gas emissions data effective January 1, 2010 to establish a baseline inventory to report to the EPA.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M costs for the period January 2021 through December 2021 is $93,149 compared to the original projection of $93,528.

Progress Summary: This project was approved by the Commission in Docket No. 20090508-EI, Order No. PSC-2010-0157-PAA-EI, issued March 22, 2010. The project is complete and in service.

Projections: There are no O&M costs projected for the period January 2022 through December 2022.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2022 through December 2022
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Gypsum Storage Facility

Project Description:

The Big Bend New Gypsum Storage Facility is necessary to maintain the FGD system operations that are required by the Consent Decree. Tampa Electric is required to operate the FGD systems in order to comply with the CAAA. Gypsum is a by-product of the FGD operations and Tampa Electric had been managing its gypsum inventory through marketing efforts to sell gypsum an existing storage facility. However, the existing storage facility was no longer sufficient to hold the entire gypsum inventory, and Tampa Electric needed an additional storage facility. The new storage facility covers approximately 27 acres and holds approximately 870,000 tons of gypsum.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $1,985,437 compared to the original projection of $1,991,084.

The actual/estimated O&M costs for the period January 2021 through December 2021 are $621,996 compared to the original projection of $1,177,899, resulting in a variance of -47.2 percent. The variance is due to a reduction in coal generation, compared to the original projection, so the amount of gypsum storage processing is reduced.

Progress Summary: This project was approved by the Commission in Docket No. 20110262-EI, Order No. PSC-2012-0493-PAA-EI, issued September 26, 2012. The project was placed in service in November 2014.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $2,030,933.

The estimated O&M costs for the period January 2022 through December 2022 are $1,213,236.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2022 through December 2022
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Coal Combustion Residuals ("CCR") Rule - Phase I & II

Project Description:

On April 17, 2015, the EPA published the CCR Rule with an effective date of October 19, 2015. The new rule requires the safe disposal of CCR in landfills and surface impoundments. Compliance activities include placing fugitive emissions dust control plans, increasing inspections, installing new groundwater monitoring wells, and closure of certain impoundments at CCR regulated management units.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 for Phase I and Phase II is $325,512 and $128,327 compared to the original projections of $362,933 and $328,169, respectively. The variances are due to timing differences in the project schedules when compared to the original projections. Because CCR removal activities have experienced project schedule delays early on, the final Project capital activities related to restoration of the site have been delayed. The project expenditures are still needed and will be incurred in the future.

The actual/estimated O&M costs for the period January 2021 through December 2021 for Phase I and Phase II are $763,222 and $5,813,349, respectively, compared to the original projections of $0 and $0, resulting in variances of 100% and 100%, respectively. The variances are due to timing differences in project schedules when compared to original projections. Another contributing factor to the increase is that more CCR material than originally estimated has been removed from the sites.

Progress Summary: Phase I was approved by the Commission in Docket No. 20150223-EI, Order No. PSC-2016-0068-PAA-EI, issued February 9, 2016. Phase II was approved by the Commission in Docket No. 20170168-EI, Order No. 2017-0483-PAA-EI, issued December 22, 2017.

Projections: Estimated depreciation plus return for the period January 2022 through December 2022 for Phase I and Phase II is $578,364 and $225,762, respectively.

The projected O&M costs for the period January 2022 through December 2022 for Phase I and Phase II are $930,000 and $0, respectively.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2022 through December 2022
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend ELG Compliance

Project Description:

On November 3, 2015, the EPA published the ELG Rule with an effective date of January 4, 2016. The ELG Rule establish limits for wastewater discharges from flue gas desulfurization ("FGD") processes, fly ash and bottom ash transport water, leachate from ponds and landfills containing coal combustion residuals ("CCR"), gasification processes, and flue gas mercury controls. The final rule requires compliance as soon as possible after November 1, 2020, and no later than December 31, 2023. Tampa Electric hired an engineering consulting firm to perform the Big Bend ELG Compliance Study, completed in 2018, that concluded with a determination of the most appropriate ELG compliance measures identified.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 for Big Bend ELG Compliance is $439,715 compared to the original projection of $782,650. This variance is due to timing differences in the project schedule when compared to the original projection. Project activities have occurred more slowly than originally projected due to permitting delays. FDEP issued its permit regarding the project on April 10, 2020. The project expenditures are still needed and will be incurred in the future.

The actual/estimated O&M costs for the period January 2021 through December 2021 for Big Bend ELG Compliance are $0, compared to $4,800 in the original projection. This variance is due to timing differences in the project schedule when compared to the original projection. The costs will be incurred in the future.

Progress Summary: The Study program was approved by the Commission in Docket No. 20160027-EI, Order No. PSC-2016-0248-PAA-EI, issued June 28, 2016, and it is now complete. The Compliance Project was approved by the Commission in Docket No. 2018007-EI, Order No. PSC-2018-0594-FOF-EI, issued December 20, 2018.

Projections: The ELG Rule Compliance program estimated depreciation plus return for the period January 2022 through December 2022 is $2,221,518.

The estimated O&M costs projected for the period of January 2022 through December 2022 are $4,944.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2022 through December 2022
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 1 Section 316(b) Impingement Mortality

Project Description:

In August 2014, the Environmental Protection Agency ("EPA") published their final rule regarding Section 316(b) of the Clean Water Act. The rule became effective in October 2014. The rule establishes requirements for cooling water intake structures ("CWIS") at existing facilities. Section 316(b) requires that the location, design, construction, and capacity of CWIS reflect the best technology available ("BTA") for minimizing adverse environmental impacts. For this project, compliance activities include modifying the existing Big Bend Unit 1 CWIS to reduce impingement mortality of affected living organisms.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $484,564, compared to the original projection of $452,502. This variance is due to timing differences in the project schedule when compared to the original projection. Earlier permit and material delivery logistic delays have been resolved and as such, project activities are getting back on track.

The actual/estimated O&M expense for the period January 2021 through December 2021 is $0 and did not vary from the original projection.

Progress Summary: This project was approved by the Commission in Docket No. 2018007-EI, Order No. PSC-2018-0594-FOF-EI, issued December 20, 2018.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $1,199,715.

There are not any O&M costs projected for the period of January 2022 through December 2022.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2022 to December 2022

Rate Class	(1) Average 12 CP Load Factor at Meter (%)	(2) Projected Sales at Meter (MWh)	(3) Effective Sales at Secondary Level (MWh)	(4) Projected Avg 12 CP at Meter (MW)	(5) Demand Loss Expansion Factor	(6) Energy Loss Expansion Factor	(7) Projected Sales at Generation (MWh)	(8) Projected Avg 12 CP at Generation (MW)	(9) Percentage of MWh Sales at Generation (%)	(10) Percentage of 12 CP Demand at Generation (%)	(11) 12 CP & 1/13 Allocation Factor (%)
RS	52.98%	9,728,165	9,728,165	2,096	1.07447	1.05324	10,246,140	2,252	49.27%	59.48%	58.69%
GS, CS	62.08%	953,392	953,392	175	1.07447	1.05323	1,004,138	188	4.83%	4.97%	4.96%
GSD, SBF	79.61%	8,099,346	8,085,442	1,161	1.06971	1.04880	8,494,582	1,242	40.85%	32.81%	33.43%
IS	105.90%	920,157	903,648	99	1.03064	1.01680	935,613	102	4.50%	2.69%	2.83%
LS1	802.58%	110,703	110,703	2	1.07447	1.05324	116,598	2	0.56%	0.05%	0.09%
TOTAL *		19,811,763	19,781,350	3,533			20,797,071	3,786	100%	100%	100%

Notes:
(1) Average 12 CP load factor based on 2022 Projected calendar data
(2) Projected MWh sales for the period January 2022 to December 2022
(3) Effective sales at secondary level for the period January 2022 to December 2022.
(4) Column 2 / (Column 1 x 8760)
(5) Based on 2022 projected demand losses.
(6) Based on 2022 projected energy losses.
(7) Column 2 x Column 6
(8) Column 4 x Column 5
(9) Column 7 / Total Column 7
(10) Column 8 / Total Column 8
(11) Column 9 x1/13 + Column 10 x 12/13

* Totals on this schedule may not foot due to rounding

Form 42 - 7P

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2022 to December 2022

Rate Class	(1) Percentage of MWh Sales at Generation (%)	(2) 12 CP & 25% Allocation Factor (%)	(3) Energy-Related Costs ($)	(4) Demand-Related Costs ($)	(5) Total Environmental Costs ($)	(6) Projected Sales at Meter (MWh)	(7) Effective Sales at Secondary Level (MWh)	**(8) Environmental Cost Recovery Factors (¢/kWh)**
RS	49.26%	58.69%	23,034,871	2,582,533	25,617,404	9,728,165	9,728,165	**0.263**
GS, CS	4.83%	4.96%	2,258,596	218,255	2,476,851	953,392	953,392	**0.260**
GSD, SBF	40.85%	33.43%	19,102,203	1,471,019	20,573,222	8,099,346	8,085,442	
Secondary								**0.254**
Primary								**0.252**
Transmission								**0.249**
IS	4.50%	2.83%	2,104,282	124,528	2,228,810	920,157	903,648	
Secondary								**0.247**
Primary								**0.244**
Transmission								**0.242**
LS1	0.56%	0.09%	261,866	3,960	265,826	110,703	110,703	**0.240**
TOTAL *	100.00%	100.00%	46,761,818	4,400,295	51,162,113	19,811,763	19,781,350	**0.259**

* Totals on this schedule may not foot due to rounding

Notes:
(1) From Form 42-6P, Column 9
(2) From Form 42-6P, Column 11
(3) Column 1 x Total Energy Jurisdictional Dollars from Form 42-1P, line 5
(4) Column 2 x Total Demand Jurisdictional Dollars from Form 42-1P, line 5
(5) Column 3 + Column 4
(6) From Form 42-6P, Column 2
(7) From Form 42-6P, Column 3
(8) Column 5 / Column 7 x 10

DOCKET NO. 20210007-EI
ECRC 2022 PROJECTION, FORM 42-7P
EXHIBIT NO. MAS-3, DOCUMENT NO. 7

Form 42 - 8P

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Calculation of Revenue Requirement Rate of Return
(in Dollars)

	(1) Jurisdictional Rate Base 2022 Adj. FESR *with Normalization* ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 2,799,863	35.02%	4.17%	1.4604%
Short Term Debt	237,124	2.97%	1.01%	0.0300%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	91,410	1.14%	2.44%	0.0279%
Common Equity	3,646,406	45.61%	10.75%	4.9030%
Accum. Deferred Inc. Taxes & Zero Cost ITC's	954,275	11.94%	0.00%	0.0000%
Deferred ITC - Weighted Cost	265,755	3.32%	7.65%	0.2543%
Total	$ 7,994,833	100.00%		6.68%

ITC split between Debt and Equity:

Long Term Debt	$ 2,799,863	Long Term Debt	46.00%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	3,646,406	Equity - Common	54.00%
Total	$ 6,446,269	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = 0.2123% * 46.00%	0.1170%
Equity = 0.2123% * 54.00%	0.1373%
Weighted Cost	0.2543%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.9030%
Deferred ITC - Weighted Cost	0.1373%
	5.0403%
Times Tax Multiplier	1.34315
Total Equity Component	6.7699%

Total Debt Cost Rate:

Long Term Debt	1.4604%
Short Term Debt	0.0300%
Customer Deposits	0.0279%
Deferred ITC - Weighted Cost	0.1170%
Total Debt Component	1.6353%
Total Cost of Capital	8.4052%

Notes:
Column (1) - Per Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology.
Column (2) - Column (1) / Total Column (1)
Column (3) - Per Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology..
Column (4) - Column (2) x Column (3)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20210007-EI EXHIBIT: 32
PARTY: Staff Exhibit 32
DESCRIPTION: FPL's response to Staff's Second Set of Interrogatories Nos. 2-16 Bates Nos. 00001-00016

32

FPL's response to Staff's Second Set of Interrogatories Nos. 2-16

Florida Power & Light Company
Docket No: 20210007-EI
Staff's 2nd Set of Interrogatories
Interrogatory No. 2

QUESTION:

For the following questions, please refer to FPL witness Deaton's direct testimony filed April 1, 2020, Exhibit RBD-1, page 4 of 74.

Project 19a – Substation Pollutant Discharge Prevention & Removal - Distribution. Please explain the 8.1 percent increase in Operational and Maintenance (O&M) expenses for Project 19a.

RESPONSE:

For responses to Interrogatories 2-10, FPL refers to FPL Witness Deaton's direct testimony filed April 1, 2021.

The 8.1%, an increase of $289,307, was primarily due to a higher than projected number of transformer repairs, which occurred after the 2020 Actual/Estimated true-up was filed due to the availability of a mobile transformer at the Hyde Park Substation. While the mobile transformer was in the area, it was decided to move the mobile transformer to the substation location so leak repairs could be performed.

A mobile transformer or other backup source is required when a transformer cannot be de-energized for leak repairs due to the demand for electricity in the surrounding area. The mobile transformer/backup source provides the electricity required while a transformer is de-energized for leak repairs.

Florida Power & Light Company
Docket No: 20210007-EI
Staff's 2nd Set of Interrogatories
Interrogatory No. 3

QUESTION:

For the following questions, please refer to FPL witness Deaton's direct testimony filed April 1, 2020, Exhibit RBD-1, page 4 of 74.

Project 21 – St. Lucie Turtle Nets. Please explain the 9.0 percent increase in O&M expenses for Project 21.

RESPONSE:

The 9.0% or $26,828 variance is primarily due to higher than projected costs associated with inspections and net cleaning of algae at the St. Lucie Plant.

Florida Power & Light Company
Docket No: 20210007-EI
Staff's 2nd Set of Interrogatories
Interrogatory No. 4

QUESTION:

For the following questions, please refer to FPL witness Deaton's direct testimony filed April 1, 2020, Exhibit RBD-1, page 4 of 74.

Project 24 – Manatee Reburn. Please explain the 10.2 percent increase in O&M expenses for Project 24.

RESPONSE:

The 10.2% or $2,414 increase in O&M expenses was primarily due to the replacement of a failed transmitter that occurred subsequent to the Estimated/Actual true-up filing. The transmitter is required to operate Units 1 and 2 to support system demand.

Florida Power & Light Company
Docket No: 20210007-EI
Staff's 2nd Set of Interrogatories
Interrogatory No. 5
Page 1 of 1

QUESTION:

For the following questions, please refer to FPL witness Deaton's direct testimony filed April 1, 2020, Exhibit RBD-1, page 4 of 74.

Project 35 – Martin Plant Drinking Water System Compliance. Please explain the 17.8 percent decrease in O&M expenses for Project 35.

RESPONSE:

The 17.8% or $1,863 decrease was primarily due to costs associated with RO/Membrane cleaning, which were included in the actual/estimated true-up filing and incurred in 2020 but were incorrectly booked to a base O&M account. A correction to move these costs from base O&M to the appropriate ECRC recoverable account has been made.

Florida Power & Light Company
Docket No: 20210007-EI
Staff's 2nd Set of Interrogatories
Interrogatory No. 6
Page 1 of 1

QUESTION:

For the following questions, please refer to FPL witness Deaton's direct testimony filed April 1, 2020, Exhibit RBD-1, page 4 of 74.

Project 41 – Manatee Temporary Heating System. Please explain the 21.1 percent decrease in O&M expenses for Project 41.

RESPONSE:

The 21.1% or $32,032 decrease in O&M expenses was primarily due to less than projected maintenance on the heaters at Ft. Myers Plant and less than projected required environmental and biological monitoring at Dania Beach Energy Center.

Florida Power & Light Company
Docket No: 20210007-EI
Staff's 2nd Set of Interrogatories
Interrogatory No. 7
Page 1 of 1

QUESTION:

For the following questions, please refer to FPL witness Deaton's direct testimony filed April 1, 2020, Exhibit RBD-1, page 4 of 74.

Project 48 – Industrial Boiler MACT. Please explain the 94.5 percent decrease in O&M expenses for Project 48.

RESPONSE:

The 94.5%, or $30,864 decrease in O&M expenses for Project 48 was primarily due to costs associated with the completion of Boiler MACT requirements, which have not yet been charged to the project due to a pending invoice correction to be provided by the vendor. The costs will be charged once a corrected invoice is received.

Florida Power & Light Company
Docket No: 20210007-EI
Staff's 2nd Set of Interrogatories
Interrogatory No. 8
Page 1 of 1

QUESTION:

For the following questions, please refer to FPL witness Deaton's direct testimony filed April 1, 2020, Exhibit RBD-1, page 4 of 74.

Project 50 – Steam Electric Effluent Guidelines Revised Rules. Please explain the 14.1 percent increase in the O&M expenses for Project 50.

RESPONSE:

The 14.1% or $650 increase in O&M expenses was the result of the incorrect coding of an invoice to an internal order associated with this project. This error has been corrected.

Florida Power & Light Company
Docket No: 20210007-EI
Staff's 2nd Set of Interrogatories
Interrogatory No. 9
Page 1 of 1

QUESTION:

For the following questions, please refer to FPL witness Deaton's direct testimony filed April 1, 2020, Exhibit RBD-1, page 4 of 74.

Project 51 – Gopher Tortoise Relocations. Please explain the 9.2 percent increase in O&M expenses for Project 51.

RESPONSE:

The 9.2% or $2,656 increase was due to more tortoise relocations than estimated at the Manatee Plant.

Florida Power & Light Company
Docket No: 20210007-EI
Staffs 2nd Set of Interrogatories
Interrogatory No. 10
Page 1 of 1

QUESTION:

For the following questions, please refer to FPL witness Deaton's direct testimony filed April 1, 2020, Exhibit RBD-1, page 4 of 74.

Project 123 – Protected Species Project. Please explain the 11.8 percent increase in the O&M expenses for Project 123.

RESPONSE:

The 11.8% or $4,000 increase was primarily associated with consultant fees for conceptual designs and options for permanent barriers at the Cape Canaveral Energy Center, which were not included in the 2020 Actual/Estimated true-up filing and incurred in December 2020. At the time of the Actual/Estimated true-up filing, the interim option was FPL's primary concern, which did not require any outside consulting services. That interim option was installed in the third quarter of 2020. Since the wildlife agencies asked FPL to continue exploring a permanent option, consulting services were requested to provide additional solutions in the fourth quarter of 2020.

Florida Power & Light Company
Docket No: 20210007-EI
Staff's 2nd Set of Interrogatories
Interrogatory No. 11

QUESTION:

For the following questions, please refer to FPL's witness Deaton's direct testimony filed April 1, 2020, Exhibit RBD-1, page 9 of 74.

Project 35 – Martin Plant Drinking Water System Compliance. Please explain the 6.07 percent decrease in Capital investment for this project.

RESPONSE:

For responses to Interrogatories 11-12, FPL refers to FPL Witness Deaton's direct testimony filed April 1, 2021.

The 6.07% or $1,225 decrease in capital revenue requirements was due to the retirement of the Martin Plant Drinking Water System in October 2020. This caused the average net investment of the plant to be less than forecasted, thus reducing the recoverable costs attributable to the project.

Florida Power & Light Company
Docket No: 20210007-EI
Staff's 2nd Set of Interrogatories
Interrogatory No. 12

QUESTION:

For the following questions, please refer to FPL's witness Deaton's direct testimony filed April 1, 2020, Exhibit RBD-1, page 9 of 74.

Project 47 – NPDES Permit Renewal Requirements. Please explain the 18.23 percent decrease in Capital investment for this project.

RESPONSE:

The 18.23% or $9,671 decrease in capital revenue requirements was primarily due to the timing of expenditures associated with the St. Lucie Nuclear Plant's Chlorine Dioxide system, which occurred later in the year than forecasted. This resulted in a lower than estimated return on investment.

Florida Power & Light Company
Docket No: 20210007-EI
Staff's 2nd Set of Interrogatories
Interrogatory No. 13

QUESTION:

For the following question, please refer to FPL's witness Sole's direct testimony filed April 1, 2020.

Please refer to page 4, lines 9 through 11. Project 3 – Continuous Emissions Monitoring Systems (CEMS). Why were the CEMS maintenance costs at the Manatee and Sanford plants lower than projected?

RESPONSE:

For responses to Interrogatories 13-16, FPL refers to FPL Witness Sole's direct testimony filed April 1, 2021.

CEMS maintenance costs at the Manatee and Sanford plants were lower than projected due to better than expected equipment reliability and a decrease in maintenance frequency.

QUESTION:

For the following question, please refer to FPL's witness Sole's direct testimony filed April 1, 2020.

Please refer to page 5, lines 3 through 8. Project 22 – Pipeline Integrity Management. Please explain the differences between the inline inspection and the alternate test with respect to the Manatee Plant pipeline integrity inspection.

RESPONSE:

In-Line-Inspection ("ILI"): ILI tool or tools capable of detecting corrosion and deformation anomalies, including dents, gouges, and grooves. For pipeline segments that are susceptible to cracks (pipe body and weld seams), an operator must use an in-line inspection tool or tools capable of detecting crack anomalies. Although this is the preferred inspection method, which is done by pushing a smart tool inside the pipe, there are situations when we cannot stop the flow of product in the pipeline to perform the inspection.

Pressure or Hydrotest: When the ILI method cannot be performed, we can pressure up the pipeline using product or water to the pipeline maximum allowable pressure x 1.1 and hold for 8 hours to ensure no leaks. The Pressure or Hydrotest method was the alternate assessment used to perform the Manatee Plant pipeline inspection that is the subject of this interrogatory.

QUESTION:

For the following question, please refer to FPL's witness Sole's direct testimony filed April 1, 2020.

Please refer to page 5, lines 11 through 13. Project 23 – Spill Prevention, Control and Countermeasures (SPCC). Please explain the type of repairs and costs for the SPCC oil diversionary structure repairs at the 40 sites.

RESPONSE:

Oil diversionary structures (curbing) are installed in FPL substations to ensure oil containment from potential mineral oil releases to the environment from transformers that remain inside the perimeter of substations. During 2020, repairs were made to broken oil diversionary structures to ensure the integrity of the structures could not be breached by a mineral oil release.

Repairs consisted of removing any crushed concrete due to adjacent construction activities or cracked concrete deteriorated due to age. The damaged area of concrete is removed, prepared with wood framing and rebar and new concrete is poured.

In 2020, repairs were made at 40 FPL substations in the amount of $288,722.

Florida Power & Light Company
Docket No: 20210007-EI
Staff's 2nd Set of Interrogatories
Interrogatory No. 16
Page 1 of 1

QUESTION:

For the following question, please refer to FPL's witness Sole's direct testimony filed April 1, 2020.

Please refer to page 20, lines 22 through 23. Project 42 – Turkey Point Cooling Canal. Please provide a breakdown of what is included in the $800,000 in O&M costs related to the NPDES/IWW permit litigation.

RESPONSE:

The $800,000 in O&M costs related to the NPDES/IWW permit litigation was estimated as follows: FPL outside counsel - 54%, travel expenses - 21%, FPL staff resources - 17%, and expert consulting services - 8%.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20210007-EI EXHIBIT: 33
PARTY: Staff Exhibit 33
DESCRIPTION: FPL's response to Staff's Third Set of Interrogatories Nos. 17-23 Bates Nos. 00017-00024

33

FPL's response to Staff's Third Set of Interrogatories Nos. 17-23

<u>QUESTION</u>:
Please refer to FPL witness Deaton's direct testimony filed July 30, 2021, Exhibit RBD-2, page 4 of 74.

a. For Project 21- St. Lucie Turtle Nets, please explain the 10.64 percent decrease in operational and maintenance (O&M) expenses for this project.

b. For Project 48 - Industrial Boiler MACT, please explain the 51.28 percent decrease in O&M expenses for this project.

<u>RESPONSE</u>:

a. The 10.64% decrease in O&M expenses for this project is primarily due to lower than projected costs associated with inspections and net cleaning of algae at the St. Lucie Plant.

b. The 51.28% decrease in O&M expenses occurred as a result of planned additional testing at the West County Energy Center that was no longer required following modification of the plant's auxiliary boiler.

QUESTION:
Please refer to FPL witness Deaton's direct testimony filed July 30, 2021, Exhibit RBD-2, page 9 of 74.

a. For Project 7 - Relocate Turbine Lube Oil Underground Piping to Above Ground, please explain the 203.07 percent decrease in capital investment for this project.

b. For Project 35 – Martin Plant Drinking Water System Compliance, please explain the 28.47 percent decrease in capital investment for this project.

c. For Project 123 – The Protected Species Project, please explain the 147.39 percent increase in capital investment for this project.

RESPONSE:

a. For Project 7, the decrease of 203.07% is due to an adjustment to depreciation expense to correct an over-collection of depreciation. A $1,689 credit to depreciation expense for the over-collected amount was posted in March 2021.

b. For Project 35, the decrease of 28.47% is due to the retirement of potable water system equipment assets in October 2020, which were not included in the original projections, and which reduced depreciation expense.

c. For Project 123, the increase in capital of 147.39% is due to a timing difference of placing plant into service. In the original projections, $203,500 was estimated to be placed in service in September, but $125,703 was actually placed in service in January, thereby increasing plant in service and depreciation expense 8 months earlier than projected.

QUESTION:
Please refer to FPL witness Deaton's direct testimony filed July 30, 2021, Exhibit RBD-2, page 23 of 74, Project 7 – Relocate Turbine Lube Oil Underground Piping to Above Ground. Please explain why the depreciation expense went from $132 in February 2021 to ($1,689) in March 2021, and then to $0 in April 2021.

RESPONSE:

a. Project 7 – Relocate Turbine Lube Oil Underground Piping to Above Ground. The reason for the change in depreciation expense is due to an adjustment to depreciation expense to correct an over-collection of depreciation. A $1,689 credit to depreciation expense for the over-collected amount was posted in March 2021.

Florida Power & Light Company
Docket No. 20210007-EI
Staff's 3rd Set of Interrogatories
Interrogatory No. 20

QUESTION:
Please refer to FPL witness Deaton's direct testimony filed July 30, 2021, Exhibit RBD-2, page 65 of 74, Project 47 – NPDES Permit Renewal Requirements. Please explain why the depreciation expense went from $8,427 in August 2021 to $16,854 in September 2021.

RESPONSE:
As shown on line 1a, column 10 of the capital schedule on page 65 of RBD-2, $2,801,208 of CWIP was placed into service in August 2021. A half month of depreciation is expensed in the month in which plant goes into service. Therefore, a half month of depreciation for the $2.8 million plant in service was recorded in August and a full month of depreciation was recorded in September.

QUESTION:
Please refer to FPL witness Deaton's direct testimony filed July 30, 2021, Exhibit RBD-2, page 68 of 74, Project 123 – The Protected Species Project. Please explain why the depreciation expense went from $310 in February 2021 to $465 in March 2021, and then back to $310 in April 2021.

RESPONSE:
Depreciation was inadvertently not applied to the additions of $125,703 that went into service in January until February 2021, therefore, the half-month depreciation expense was missing for the month of January. To correct this, a depreciation adjustment for the half month of depreciation expense associated with January was booked in March.

QUESTION:
Please refer to FPL witness Sole's direct testimony filed July 30, 2021, page 7, lines 14-16. Please explain how using reclaimed water as a primary source for cooling Unit 5 will improve its resiliency.

RESPONSE:
The resiliency of Unit 5 operations will be improved by having two cooling water sources for the unit. Reclaimed water will serve as the primary source and groundwater will be available as a backup source should reclaimed water be unavailable in the quantity and/or quality acceptable for use in Unit 5. Utilizing reclaimed water as a primary cooling water source can provide a more reliable water source during times of drought as reclaimed water is not subject to the South Florida Water Management District's mandatory drought conservation measures as required by Turkey Point's Conditions of Certification Condition XIII.B.1 and Chapter 40E-21 Florida Administrative Code (F.A.C.). Further, use of the Upper Floridan Aquifer groundwater for cooling water is subject to mitigation measures as outlined in Turkey Point's Conditions of Certification Condition XIII.B.2, including, but not limited to, a reduction in groundwater pumping rates in the event there are impacts to existing legal uses. Use of reclaimed water is not subject to mitigation measures and provides more resiliency for Unit 5 operations.

QUESTION:
Please refer to FPL witness Sole's direct testimony filed July 30, 2021, pages 2 through 9.

a. Does FPL return the reclaimed water used for cooling Unit 5 to Miami-Dade's South District Wastewater Treatment Plant for treatment and disposal? If not, please explain how the reclaimed water is disposed once it has been used for cooling Unit 5.

b. The Agreement states that FPL is responsible for designing and constructing an advanced treatment system at Turkey Point to further treat the reclaimed water for use in the cooling towers. As the reclaimed water from Miami-Dade's South District Wastewater Treatment Plant is already treated, please explain what extra treatment is needed to make the reclaimed water suitable for use in the cooling towers.

RESPONSE:

a. No. FPL intends to dispose of reclaimed water used for Unit 5 cooling using a new underground injection control system to be constructed at the Turkey Point site pursuant to the FPL Miami-Dade County Agreement (Exhibit MWS-9). Additionally, the FPL Miami-Dade County Agreement precludes disposal of reclaimed water to the Turkey Point cooling canals, or surface waters of surrounding wetlands, and Biscayne Bay.

b. The CWRC facility will include biological treatment trains to reduce nutrients, secondary clarifiers and filters to reduce total suspended solids, and a chlorine contact system for disinfection. This level of treatment is required for use in the cooling towers and heat exchanger surfaces to prevent scaling and corrosion of the condenser and other power generation equipment. Further, the additional disinfection is needed to comply with Chapter 62-610.668(2)(c), F.A.C. to control biological growth in open cooling towers utilizing reclaimed water. FPL's ownership and operation of the CWRC facility will help ensure a consistent level of water quality for use in the Unit 5 cooling towers.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20210007-EI EXHIBIT: 34
PARTY: Staff Exhibit 34
DESCRIPTION: FPL's response to Staff's Fourth Set of Interrogatories Nos. 24-29 Bates Nos. 00025-00030

34

FPL's response to Staff's Fourth Set of Interrogatories Nos. 24-29

Florida Power & Light Company
Docket No. 20210007-EI
Staff's 4th Set of Interrogatories
Interrogatory No. 24

QUESTION:
Please refer to FPL witness Deaton's direct testimony filed August 27, 2021, page 7, lines 3 through 8. Please fill out the following table indicating the amortization amounts for the identified ECRC projects.

RESPONSE:
Please see requested information below included in FPL's 2022 Projection Filing.

	Monthly Amortization Amount Per Project				
Project Number	Martin 1&2 (beginning 1/1/22)	Manatee 1&2 (beginning 2/1/22)	Lauderdale 4&5 (beginning 1/1/22)	Scherer 4 (beginning 2/1/22)	Gulf Clean Energy Center Units 4-7 (beginning 1/1/22)
3	$1,880	$1,763	$759	$338	
5	$5,111	$3,761			
8	$29	$355			
12				$867	
20	$2,215				
22		$1,924			
23	$2,113	$3,915	$18		$21
24		$65,742			
27					$13,936
35	$738				
54				$438,467	
402					$91,367
413					$561
419					$212,837
422					$31,803
426	$548,742	$441,102		$1,468,748	$1,293,421
Total	**$560,828**	**$518,562**	**$776**	**$1,908,420**	**$1,643,948**

Amortization amounts reflected above are based on projected remaining net book value of the retired assets as of May 31, 2021 and are slightly different from the unrecovered investment reflected on Exhibit D of FPL's proposed Settlement Agreement pending approval by the Commission in Docket No. 20210015-EI. Note, the actual amount of amortization recovered through ECRC will be based on the unrecovered investment on FPL's books and records at the time amortization begins.

QUESTION:
Please refer to FPL witness Deaton's direct testimony filed August 27, 2021, page 7, lines 9 through 19. Please indicate the amount by which the following proposed adjustments from the proposed Settlement Agreement filed in Docket No. 20210015 will impact the ECRC projects. As part of your response, please use the project number to identify the ECRC project.

a. Dismantlement accrual

b. Scherer ash pond closure costs

c. Groundwater Contamination Investigation and Solid & Hazardous Waste Programs

RESPONSE:
Below are the amounts for the requested adjustments from the proposed Settlement Agreement filed in Docket No. 20210015-EI discussed on lines 9 through 19 on page 7 of FPL witness Deaton's testimony filed on August 27, 2021:

a. – b. Please refer to Attachment I for the proposed dismantlement accrual reserve transfers between units impacting ECRC projects and the Scherer ash pond closure costs dismantlement reserve transfer from base to ECRC.

c. The proposed adjustment for the Groundwater Contamination Investigation and Solid & Hazardous Waste Program O&M costs to be transferred from base to ECRC is $496,836. This adjustment will increase the O&M reflected for ECRC project numbers 19 - Oil-filled Equipment and Hazardous Substance Remediation and 430 - General Solid & Hazardous Waste by $408,036 and $88,800, respectively.

Project	Project Description	Unit	Function	Reserve Transferred In [1,2]	Reserve Transferred Out [1]	Current Accrual	Revised Accrual Effective 1/1/2022
Project # 37	DE SOTO SOLAR PROJECT	Desoto Solar	Other Generation Plant	$ -	$ (1,240,160)	$ 146,241	$ 109,005
Project # 38	SPACE COAST SOLAR PROJECT	Space Coast Solar	Other Generation Plant	$ -	$ (499,367)	$ 52,699	$ 25,125
Project # 39	MARTIN SOLAR PROJECT	Martin Solar	Other Generation Plant	$ -	$ (5,079,140)	$ 594,662	$ 546,687
Project # 54	COAL COMBUSTION RESIDUALS	Scherer (FPL)	Steam Generation Plant	$ 65,740,072	$ -	$ -	$ 7,800,751
Project # 54	COAL COMBUSTION RESIDUALS	Crist Plant	Steam Generation Plant	$ -	$ (16,607,933)	$ 307,876	$ -
Project # 54	COAL COMBUSTION RESIDUALS	Daniel Plant	Steam Generation Plant	$ 14,619,708	$ -	$ 317,179	$ -
Project # 54	COAL COMBUSTION RESIDUALS	Scherer (Gulf)	Steam Generation Plant	$ 24,159,836	$ -	$ 33,273	$ 2,553,939
				$ 104,519,616	**$ (23,426,600)**	**$ 1,451,930**	**$ 11,035,507**

Notes:

[1] Amounts represent dismantlement reserve transfers related to the environmental cost recovery clause (ECRC) only. All other dismantlement reserve transfers relate to base rates and are not reflected herein.

[2] Amount reflected for Scherer (FPL) represents the Scherer Ash Pond Closure Costs dismantlement reserve transfer from base to ECRC.

QUESTION:
Please refer to FPL witness Deaton's direct testimony filed August 27, 2021, Exhibit RBD-3, pages 22 and 23 of 171, Project 8 – Oil Spill Cleanup/Response Equipment Project – Intermediate and Peaking. Please explain why Construction Work In Progress (CWIP) (line 4) does not change when there are Expenditures/Additions (line 1a).

RESPONSE:
The Construction Work In Progress ("CWIP") amounts on line 4 of pages 22 and 23 show a balance of $1,316 for the intermediate strata and an offsetting ($1,316) for the peaking strata. This is due to an error made in May 2021 when reclassifying CWIP between the intermediate and peaking strata. The 2021 Final True-Up will reflect corrected CWIP balances for these two strata.

The CWIP (line 4) amounts reflected for the intermediate strata and peaking strata (pages 22 and 23 of filing) do not change because 100% of the expenditures are projected to be closed to plant in service each month in 2022.

QUESTION:
Please refer to FPL witness Deaton's direct testimony filed August 27, 2021, Exhibit RBD-3, page 143 of 171, Project 124 – Miami-Dade Clean Water Recovery Center.

a. Please explain how cost-effectiveness was determined. As part of your response, explain whether the cost-effectiveness of each alternative compliance method was determined.

b. For each year the project is in service, please provide the estimated residential annual bill impact for a customer using 1,000 kWh per month. As part of your response, please complete the table below.

RESPONSE:

a. As noted in Michael W. Sole's July 29, 2021 testimony, the CWRC project stems from an agreement between FPL and Miami-Dade County to construct and operate a wastewater reuse system and to further compliance with environmental and reclaimed water reuse requirements ("the Agreement"). In meeting FPL's obligations in the Agreement, FPL did design the project in a manner that reduced costs and minimized environmental impacts. The location of the CWRC and route of the waterline were sited to maximize existing resources and reduce costs. The CWRC was sited in an upland location adjacent to Unit 5 to minimize infrastructure needs and avoid wetland impacts and associated mitigation costs. The corridor for the CWRC waterline utilizes existing infrastructure, including an FPL power transmission corridor, to the greatest extent practicable in order to maximize use of FPL-owned property and minimize environmental impacts. Approximately 78% of the corridor is located within the existing FPL transmission line right-of-way. Furthermore, FPL will competitively bid the engineering, procurement and construction of the project. FPL benefits from strong market presence allowing it to leverage corporate-wide procurement activities to the specific benefit of individual procurement activities. FPL's Project Controls group maintains the project scope, budget, and schedule and tracks project costs through various approval processes, procedures, and databases. These measures will ensure the CWRC project costs are reasonable and prudently incurred.

b.

Year	Average Monthly Impact	Annual Impact	Cumulative Impact
2022	$0.01	$0.12	$0.12
2023	$0.09	$1.08	$1.20
2024	$0.18	$2.16	$3.36
2025	$0.25	$3.00	$6.36
2026	$0.25	$3.00	$9.36

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20210007-EI EXHIBIT: 35
PARTY: Staff Exhibit 35
DESCRIPTION: FPL's response to Staff's Fifth Set of Interrogatories No. 28 Bates Nos. 00031-00035

35

FPL's response to Staff's Fifth Set of Interrogatories No. 28

QUESTION:
Please refer to the August 2021 Solar Report filed on September 20, 2021, Document No. 11304-2021 and the July 2021 Solar Report filed August 20, 2021, Document No. 09583-2021 for the following question. Please verify that the emissions reductions for July 2021 and August 2021 were the same for both months. If they were not the same, please provide an updated report for the incorrect month.

RESPONSE:
Attachment I to this response provides a revised report for August 2021 reflecting corrected emissions reductions. FPL will file a revised August 2021 report that includes the corrected emissions reductions amounts in the September 2021 Solar Report being filed on October 20th.

Florida Power & Light Company
Actual Data for Next Generation Solar Centers
Environmental Cost Recovery Clause
Period of: August 2021

			Average Hourly Net Output (kWh)		
	Hour of Day	System Firm Demand (MW)	DESOTO	SPACE COAST	MARTIN SOLAR
1	1	14,586	(52)	(19)	(201)
2	2	13,712	(52)	(19)	(212)
3	3	13,079	(51)	(18)	(227)
4	4	12,671	(51)	(18)	(222)
5	5	12,520	(51)	(18)	(217)
6	6	12,744	(51)	(18)	(214)
7	7	13,215	(54)	(19)	(235)
8	8	13,628	1,454	272	(330)
9	9	14,877	7,585	1,539	(587)
10	10	16,526	10,931	3,166	217
11	11	18,113	12,068	4,627	4,349
12	12	19,520	12,500	5,989	8,391
13	13	20,598	12,515	6,461	11,524
14	14	21,332	13,374	6,038	11,833
15	15	21,737	12,213	5,636	10,130
16	16	21,851	11,727	5,166	9,573
17	17	21,720	9,133	3,606	9,406
18	18	21,330	5,439	2,341	8,663
19	19	20,637	2,746	990	6,600
20	20	19,746	507	135	2,145
21	21	19,179	(65)	(29)	(104)
22	22	18,248	(54)	(24)	(168)
23	23	16,998	(53)	(21)	(180)
24	24	15,683	(53)	(19)	(190)

REVISED 10/4/21

Florida Power & Light Company
Actual Data for Next Generation Solar Centers
Environmental Cost Recovery Clause
Period of: August 2021

		Net Capability (MW)	(1) Net Generation (MWh)	Capacity Factor (%)	Percent of Total Generation (%)	(2) Total System Net Generation (MWh)
1	DESOTO	25	3,460	18.6%	0.03%	13,004,489
2	SPACE COAST	10	1,418	19.1%	0.01%	
3	MARTIN SOLAR	75	2,472	4.4%	0.02%	
4	Total	110	7,350	9.0%	0.06%	

		Natural Gas Displaced (MCF)	(2) Cost of NG ($/MCF)	Oil Displaced (Bbls)	(2) Cost of Oil ($/Bbl)	Coal Displaced (Tons)	(3) Cost of Coal ($/Ton)
5	DESOTO	26,282	$5.38	59	$74.97	0	N/A
6	SPACE COAST	10,809	$5.38	26	$74.97	0	N/A
7	MARTIN SOLAR	21,025	$5.38	80	$74.97	0	N/A
8	Total	58,116	$312,657	165	$12,336	0	$0

		CO2 Reductions (Tons)	Nox Reductions (Tons)	SO2 Reductions (Tons)	Hg Reductions (lbs)
9	DESOTO	1,582	0.6	0.1	0.00
10	SPACE COAST	652	0.3	0.1	0.00
11	MARTIN SOLAR	1,283	0.5	0.2	0.00
12	Total	3,517	1.4	0.4	0.00

		O&M ($)	(4) Carrying Costs ($)	(5) Capital ($)	(6) Other ($)	Fuel Cost ($)	Total Cost of Generation ($)
13	DESOTO	$62,657	$656,998	$432,562	($148,208)	$0	$1,004,008
14	SPACE COAST	$9,656	$307,091	$194,936	($62,871)	$0	$448,812
15	MARTIN SOLAR	$243,522	$2,092,622	$1,031,008	($402,196)	$0	$2,964,956
16	Total	$315,835	$3,056,711	$1,658,506	($613,275)	$0	$4,417,777

(1) Net Generation data represents a calendar month.
(2) Total System Net Generation from Schedule A3. Fuel Cost per unit data from Schedule A3.
(3) Fuel Cost per unit data from Schedule A4.
(4) Carrying Cost data represents return on average net investment.
(5) Capital Cost data represents depreciation expense on net investment.
(6) Other Cost data represents dismantlement costs and amortization on ITC.

REVISED 10/4/21

Florida Power & Light Company
Actual Data for Next Generation Solar Centers
Environmental Cost Recovery Clause
Period of: Year-to-Date (January - August) 2021

		Net Capability (MW)	(1) Net Generation (MWh)	Capacity Factor (%)	Percent of Total Generation (%)	(2) Total System Net Generation (MWh)
1	DESOTO	25	31,410	21.5%	0.04%	85,569,514
2	SPACE COAST	10	11,457	19.6%	0.01%	
3	MARTIN SOLAR	75	22,310	5.1%	0.03%	
4	Total	110	65,177	10.2%	0.08%	

		Natural Gas Displaced (MCF)	(2) Cost of NG ($/MCF)	Oil Displaced (Bbls)	(2) Cost of Oil ($/Bbl)	Coal Displaced (Tons)	(3) Cost of Coal ($/Ton)
5	DESOTO	200,300	$4.75	668	$73.38	2,377	$47.96
6	SPACE COAST	73,375	$4.75	202	$73.38	859	$47.96
7	MARTIN SOLAR	150,707	$4.75	856	$73.38	1,721	$47.96
8	Total	424,383	$2,014,476	1,726	$126,636	4,957	$237,716

		CO2 Reductions (Tons)	Nox Reductions (Tons)	SO2 Reductions (Tons)	Hg Reductions (lbs)
9	DESOTO	16,405	7.5	1.8	0.05
10	SPACE COAST	5,966	2.7	0.6	0.02
11	MARTIN SOLAR	12,403	5.9	2.2	0.04
12	Total	34,775	16.0	4.5	0.11

		O&M ($)	(4) Carrying Costs ($)	(5) Capital ($)	(6) Other ($)	Fuel Cost ($)	Total Cost of Generation ($)
13	DESOTO	$376,041	$5,381,118	$3,460,354	($1,185,664)	$0	$8,031,849
14	SPACE COAST	$141,242	$2,513,900	$1,559,486	($502,968)	$0	$3,711,661
15	MARTIN SOLAR	$2,661,124	$17,056,158	$8,242,389	($3,217,568)	$0	$24,742,103
16	Total	$3,178,407	$24,951,176	$13,262,230	($4,906,200)	$0	$36,485,612

(1) Net Generation data represents a calendar month.
(2) Total System Net Generation from Schedule A3. Fuel Cost per unit data from Schedule A3.
(3) Fuel Cost per unit data from Schedule A4.
(4) Carrying Cost data represents return on average net investment.
(5) Capital Cost data represents depreciation expense on net investment.
(6) Other Cost data represents dismantlement costs and amortization on ITC.

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Gulf's response to Staff's First Production of Documents No. 1

(No. 1 has attachments)

Gulf Power Company
Docket No: 20210007-EI
Staffs First POD
Request No: 1
Page 1 of 1

QUESTION:

Please refer to Gulf witness Hume's direct testimony filed July 30, 2021, Exhibit RLH-2, page 13 of 54, Project 2 - Crist 5, 6, and 7 Precipitator Projects - Base. Please provide the revised 2021 Midcourse Correction schedules from Order No. PSC-2021-0115-PAA-EI in PDF and Excel format with formulas intact.

RESPONSE:

Please see files provided - "FINAL ECRC 2020 Actual Estimated Midcourse Schedules-", "FINAL ECRC 2021 Projection Midcourse Schedules - Clean" and "Gulf Mid-Course "Correction Sch".

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20210007-EI EXHIBIT: 37
PARTY: Staff Exhibit 37
DESCRIPTION: Gulf's response to Staff's First Set of Interrogatories Nos. 1-4 Bates Nos. 00038-00042

37

Gulf's response to Staff's First Set of Interrogatories Nos. 1-4

Gulf Power Company
Docket No: 20210007-EI Gulf
Staffs 1st Set INTs
Interrogatory No: 1

QUESTION:

Please refer to GPC's witness Hume's direct testimony filed April 1, 2021, Exhibit RLH-1 – Appendix 1, page 43 of 55, Form 42-8A and GPC's witness Markey's direct testimony filed April 1, 2020, Exhibit RLH-1 – Appendix 1, page 34 of 46, Schedule 8A. Form 42-8A, page 43 of 55 does not reflect the End of Period CWIP - Non-Interest Bearing indicated on Schedule 8A, page 34 of 46; instead Form 42-8A, page 43 of 55 reflects a total of $0 (Line 4). Please indicate the appropriate amount for End of Period CWIP - Non-Interest Bearing that should be reflected on Form 42-8A.

RESPONSE:

In Gulf's 2020 Actual/Estimated filing, the schedules reported an end of period CWIP balance for Program 427 of $396,465. However, during the transition to FPL's automated system, it was discovered in August 2020 that the CWIP balance was incorrectly assigned to program 427. This error was corrected in January 2020, and the CWIP balance of $396,465 was moved to Program 425. The End of Period CWIP balance for Program 427 is $0 as filed in the 2020 Final True-up Filing.

Gulf Power Company
Docket No: 20210007-EI Gulf
Staffs 1st Set INTs
Interrogatory No: 2

QUESTION:

For the following questions, please refer to GPC's witness Hume's direct testimony filed April 1, 2021, Exhibit RLH-1 – Appendix 1.

Please refer to Exhibit RLH-1, page 43 of 55, Form 42-8A. Please explain the Crist Closed Ash Landfill Reg Asset (Line 5) calculation of 2,401,279 for Actual January.

RESPONSE:

As discussed in Witness Hume's 2020 Final True-up testimony, filed on April 1, 2021, expenditures associated with the Crist Closed Ash Landfill ("Crist CAL") project were moved to deferred FERC 182 regulatory asset accounts beginning January 2020. Costs associated with the Crist CAL project were recorded to regulatory asset accounts and will be amortized to expense since the costs are not associated with an operating asset that will incur future benefit.

The $2,401,279 represents the accumulation of the expenditures as of January 2020 for the Crist CAL project. This project was approved by Order No. PSC-2019-0500-FOF-EI issued November 22, 2019.

Gulf Power Company
Docket No: 20210007-EI Gulf
Staffs 1st Set INTs
Interrogatory No: 3

QUESTION:

For the following questions, please refer to GPC's witness Hume's direct testimony filed April 1, 2021, Exhibit RLH-1 – Appendix 1.

Please refer to Exhibit RLH-1, page 44 of 55, Form 42-8A. Please explain the Less: Accumulated Depreciation (Line 3) calculation of 37,389,070 for Actual June.

RESPONSE:

The Accumulated Depreciation calculation for June 2020 is as follows:

Prior month accumulated depreciation	$ (34,830,255)
- depreciation expense	$ 59,639
- dismantlement expense	$ 54,861
+ other	$ 100,903
+ retirements	$ 0
- adjustment	$ 2,545,219
Ending balance accumulated depreciation	$ (37,389,070)

Gulf Power Company
Docket No: 20210007-EI Gulf
Staffs 1st Set INTs
Interrogatory No: 4

QUESTION:

For the following questions, please refer to GPC's witness Hume's direct testimony filed April 1, 2021, Exhibit RLH-1 – Appendix 1.

Please refer to Exhibit RLH-1, page 44 of 55, Form 42-8A. Please explain the Less: Accumulated Depreciation (Line 3) calculation of 34,523,627 for Actual December.

RESPONSE:
The Accumulated Depreciation calculation for December 2020 is as follows:

Prior month accumulated depreciation	$ (36,241,342)
- depreciation expense	$ 62,417
- dismantlement expense	$ 54,861
+ other	$ 1,834,416
+ retirements	$ 0
- adjustment	$ (577)
Ending balance accumulated depreciation	$ (34,523,627)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20210007-EI EXHIBIT: 38
PARTY: Staff Exhibit 38
DESCRIPTION: Gulf's response to Staff's Second Set of Interrogatories No. 5 Bates Nos. 00043-00044

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Gulf's response to Staff's Second Set of Interrogatories No. 5

Gulf Power Company
Docket No: 20210007-EI Gulf
Staffs 2nd Set INTs
Interrogatory No: 5

QUESTION:

Please refer to Gulf's witness Hume's Exhibit RLH-1, MS Excel file , "2020 ECRC Final True Up_Working File - FINAL CLEAN.xlsx", tab "ECRC_42_8A", Line 1424. Please explain why the formulas to calculate the Less: Accumulated Depreciation for June and December differ from all other months.

RESPONSE:

The calculation Less: Accumulated Depreciation correctly captured adjustments to the reserve balance. Due to the nature of the contra-asset account the data transferred from the books and records had a numerical sign (+/-) that was opposite of the sign presented in tab, "ECRC_42_8A", Line 1424. Rather than change the sign from the transferred data adjustment we opted to adjust the formula to reflect the correct impact to the balance. The purpose of this adjustment was to remove accumulated depreciation from the project. The calculation correctly reflects the removal. We've confirmed the results are same through recalculation.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20210007-EI EXHIBIT: 39
PARTY: Staff Exhibit 39
DESCRIPTION: Gulf's response to Staff's Third Set of Interrogatories Nos. 6-10 Bates Nos. 00045-00051

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Gulf's response to Staff's Third Set of Interrogatories Nos. 6-10

QUESTION:

Please refer to Gulf witness Hume's direct testimony filed April 1, 2021, Exhibit RLH-1, page 24 of 55, Project 11 - Crist Bulk Tanker Unloading Second Containment - Base. Please also refer to Gulf witness Hume's direct testimony filed July 30, 2021, Exhibit RLH-2, page 24 of 54, Project 11. Please explain why the 2020 Actual Plant-in Service/Depreciation Base of $101,495 and Less: Accumulated Depreciation of ($91,771) for December does not match the 2021 Beginning of Period Amount's Plant-in Service/Depreciation Base of $50,748, and Less: Accumulated Depreciation of ($41,024).

RESPONSE:

In October 2020, there were retirements made that were not itemized on the Excel schedules used for the 2020 Final True Up filing submitted on April 1, 2021 resulting in the mismatch between 2020 and 2021 balances. However, the net investment ending balance for 2020 from the Final True-up filed April 1, 2021, Exhibit RLH-1, page 24 of 55 line 5, matches the beginning balance for 2021 from the Actual/Estimated filed July 30, 2021, Exhibit RLH-2, page 24 of 54 line 6. The Company's ledger reflected the correct balances from October 2020 and the additional beginning balance detail was added for the Actual/Estimated filing submitted on July 30, 2021.

QUESTION:

Please refer to Gulf witness Hume's direct testimony filed April 1, 2021, Exhibit RLH-1, page 26 of 55, Project 13 - Sodium Injection System-Base. Please also refer to Gulf witness Hume's direct testimony filed July 30, 2021, Exhibit RLH-2, page 26 of 54, Project 13. Please explain why the 2020 Actual Plant-in Service/Depreciation Base of $284,622 and Less: Accumulated Depreciation of ($149,884) for December does not match the 2021 Beginning of Period Amount's Plant-in Service/Depreciation Base of $0, and Less: Accumulated Depreciation of $134,738.

RESPONSE:

In October 2020, there were retirements made that were not itemized on the Excel schedules used for the 2020 Final True Up filing submitted on April 1, 2021 resulting in the mismatch between 2020 and 2021 balances. However, the net investment ending balance for 2020 from the Final True-up filed April 1, 2021, Exhibit RLH-1, page 26 of 55 line 5, matches the beginning balance for 2021 from the Actual/Estimated filed July 30, 2021, Exhibit RLH-2, page 26 of 54 line 6. The Company's ledger reflected the correct balances from October 2020 and the additional beginning balance detail was added for the Actual/Estimated filing submitted on July 30, 2021.

QUESTION:

Please refer to Gulf witness Hume's direct testimony filed July 30, 2021, Exhibit RLH-2, page 41 of 54, Project 26 - Air Quality Compliance Program - General. Please also refer to Gulf witness Hume's direct testimony filed April 1, 2021, Exhibit RLH-1, Project 26. Please explain why Gulf added the "General" portion of the program.

RESPONSE:

A review of Gulf Property records revealed that there were Fiber Optic assets in Project 26 that needed to be reclassified under General Plant because these assets serve a general use in connection with utility operations. In accordance with Rule 25-6.0142 Uniform Retirements for Electric Utilities, Gulf transferred the Fiber Optic Communication Assets to Account 397-Communication Equipment in April 2021. Identifying the assets as General provides a more accurate separation of costs between retail and wholesale.

ACCOUNT 397 - COMMUNICATION EQUIPMENT

PROPERTY UNIT INCLUDES:
COST INSTALLED OF TELEPHONE, TELEGRAPH AND WIRELESS EQUIPMENT FOR GENERAL USE IN CONNECTION WITH UTILITY OPERATIONS, SUCH AS METALLIC LAND LINES FOR COMMUNICATION, MICROWAVE SYSTEMS, TWO-WAY COMMUNICATION SYSTEMS, SWITCHING EQUIPMENT AND SPECIAL TEST EQUIPMENT (NOT DUPLICATED IN ACCOUNT 395.) SUCH COST SHOULD BE AMORTIZED OVER A 5 YEAR PERIOD AND NO PROPERTY RECORDS MAINTAINED EXCEPT AS A VINTAGE GROUP.

FIBER-OPTIC EQUIPMENT FOR COMMUNICATION
PROPERTY UNIT INCLUDES:
COST INSTALLED OF COMMUNICATION EQUIPMENT ASSOCIATED WITH FIBER OPTIC TECHNOLOGY, INCLUDING FIBER CABLE, MULTIPLEXERS, PATCH PANELS, AND SPLICE BOXES.

RETIREMENT UNIT DESCRIPTION	RETIREMENT UNIT
FIBER TRANSMISSION CABLE OR CONDUCTOR	2 CONTINUOUS SPANS, WITH OR WITHOUT ASSOCIATED APPURTENANCES
OVERHEAD FIBER CABLE	EACH SPAN
PATCH PANEL	EACH
SPLICE BOX	EACH
CONDUIT - OVERHEAD	EACH SPAN
CONDUIT OTHER THAN OVERHEAD	2 CONTINUOUS SPANS
REFLECTOMETER	EACH
VIDEO CODER/DECODER	EACH
DIGITAL MULTIPLEXER	EACH
DIRECT BURIED DUCT BANK	2 CONTINUOUS SPANS
CONCRETE ENCASED DUCT BANK	2 CONTINUOUS SPANS
CHANNEL BANK EQUIPMENT	EACH
FIBER OPTIC TERMINAL/REGENERATOR	EACH

QUESTION:

Please refer to Gulf witness Hume's MS Excel file of Exhibit RLH-2, "FINAL 2021 ECRC Actual Estimated True Up - Clean 8.4.21", tab "ECRC_42_8E" Project 28- Coal Combustion Residuals- Intermediate. Please explain why the formulas to calculate the Capital Recovery Unamortized Balance change from September to October. Specifically, the addition of other Investments to other Investment Expenses.

RESPONSE:

This is an error in the formula for October through December. As a result, Gulf under-stated its "Total Recoverable Costs" for October – December in the amount of $24,915. This will be corrected in the 2021 final true up filing.

QUESTION:

Please refer to Gulf witness Hume's direct testimony filed July 30, 2021, Exhibit RLH-2. Please explain where Gulf is accounting for the amortization of the regulatory assets approved by Order No. PSC-2021-0115-PAA-EI for all projects associated with the regulatory assets for the following:

a. Page 13 of 54, Project 2 - Crist 5, 6, and 7 Precipitator Projects – Base
b. Page 24 of 54, Project 11 - Crist Bulk Tanker Unloading Second Containment – Base
c. Page 26 of 54, Project 13 - Sodium Injection System – Base
d. Page 31 of 54, Project 19 - Crist FDEP Agreement for Ozone Attainment – Base
e. Page 36 of 54, Project 22 - Precipitator Upgrades for CAM Compliance – Base
f. Page 37 of 54, Project 24 - Crist Water Conservation – Base
g. Page 40 of 54, Project 26 - Air Quality Compliance Program – Base

RESPONSE:

In accordance with the Petition for Approval of Regulatory Assets Related to the Retirements of the Coal Generation Assets at Plant Crist, filed with the Commission in Docket No. 2020007-EI on November 10, 2020. Gulf sought to defer recovery of the regulatory assets and determination of the associated amortization period until Gulf's base rates are next reset in a general base rate proceeding.

Pending the Commission's approval of the Settlement Agreement proposed in Docket No. 20210015 on August 10, 2021, amortization of the regulatory asset will begin in January 2022.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20210007-EI EXHIBIT: 40
PARTY: Staff Exhibit 40
DESCRIPTION: DEF’s response to Staff’s Second Set of Interrogatories No. 2 Bates Nos. 00052-00061

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DEF’s response to Staff’s Second Set of Interrogatories No. 2

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause	Docket No. 20210007-EI Dated: June 1, 2021

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO
<u>STAFF'S SECOND SET OF INTERROGATORIES (NOS. 2-3)</u>

Duke Energy Florida, LLC ("DEF"), responds to Staff's Second Set of Interrogatories to DEF (Nos. 2-3), as follows:

<u>INTERROGATORIES</u>

2. For the following questions, please refer to DEF witness McDaniel's direct testimony filed April 1, 2021.

   a. Please refer to page 3, lines 10-19. Project 1 - Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention. Please describe the "unexpected expenses" that were incurred as a result of the Florida Department of Environmental Projection's (FDEP) requests.

<u>Response</u>:

a. Unexpected expenses were incurred as a result of FDEP requests for closures of groundwater wells. These included the services provided by the environmental consulting company which conducted the assessment and investigation of those wells and contractor oversight of supplementary vendors required for the well closures. Additional vendor expenses included certified well drillers, vegetation removal contractors, equipment rental and a survey company. Environmental consultant expenses included groundwater well closure report preparation and submittals, subsequent amendment of the Declaration of Restrictive Covenants (DRC) for recordings with County Clerks of Courts and submittal to FDEP.

b. Please refer to page 4, line 13 through page 5, line 3. Project 6 - Cooling Water 23 Intake - 316(b). Please identify when DEF anticipates the FDEP will complete its review of the permit renewal application and when the additional costs will be incurred.

Response:

b. While it is difficult to predict FDEP's timeline for review, DEF anticipates FDEP could potentially issue the final NPDES permits, at the earliest, during the fourth quarter of 2021; however, it is more likely permit issuance would occur during early 2022. Additional costs will begin to be incurred shortly after the permit is granted.

c. Please refer to page 6, lines 11-16. Project 17 - Mercury & Air Toxic Standards (MATS) – CR 4&5. Please explain whether the tests and inspections are no longer required or if they are rescheduled to a futured date.

Response:

c. The MATS inspections were required and completed in 2020. During the CR4 2020 outage, the scope of work typically performed as part of the inspections was not needed due to equipment that had already been mobilized as part of other work occurring concurrently.

After further review, the cited Q/A was missing the words, "work and costs associated with the" tests and inspections. Therefore, the testimony should have read, "The MATS – CR 4&5 O&M variance is $90k, or 74% lower than forecasted, primarily due to work and costs associated with the inspections that did not need to be completed in Fall 2020."

Duke Energy Florida, LLC
Docket No. 20210007-EI
Staff's Second Set of ROGs
Interrogatory No. 3

3. Please refer to the March 2021 Solar Report filed on April 30, 2021, Document No. 03764-2021 for the following question. For the Santa Fe and Twin Rivers solar projects, please complete the following tables.

Solar Project Name	
	Projected Net Generation (MWh)
January	
February	
March	
April	
May	
June	
July	
August	
September	
October	
November	
December	

Solar Project Name			
	NG Displaced (MCF)	Oil Displaced (Bbl)	Coal Displaced (Ton)
Projected for a year			

Solar Project Name				
	CO_2 Reductions (Tons)	NO_x Reductions (Tons)	SO_2 Reductions (Tons)	Hg Reductions (lbs)
Projected for a year				

Solar Project Name		
	Projected Peak Day Performance	
Time of Day	Winter Peak Day (kW) (January)	Summer Peak Day (kW) (August)

1:00 AM		
2:00 AM		
3:00 AM		
4:00 AM		
5:00 AM		
6:00 AM		
7:00 AM		
8:00 AM		
9:00 AM		
10:00 AM		
11:00 AM		
12:00 PM		
1:00 PM		
2:00 PM		
3:00 PM		
4:00 PM		
5:00 PM		
6:00 PM		
7:00 PM		
8:00 PM		
9:00 PM		
10:00 PM		
11:00 PM		
12:00 AM		

Response:
Please see DEF's response on the following three pages.

Duke Energy Florida, LLC
Docket No. 20210007-EI
Staff's Second Set of ROGs
Interrogatory No. 3

	Santa Fe	Twin Rivers
	Projected Net Generation (MWh)	
January	11,670	10,410
February	12,270	11,310
March	17,080	16,030
April	18,600	17,610
May	20,600	19,690
June	18,750	17,640
July	18,090	18,230
August	16,940	16,750
September	15,180	15,370
October	15,370	15,010
November	12,430	11,340
December	10,400	8,870

	Santa Fe			Twin Rivers		
	NG Displaced (MCF)	Oil Displaced (Bbl)	Coal Displaced (Ton)	NG Displaced (MCF)	Oil Displaced (Bbl)	Coal Displaced (Ton)
Projected for a year	1,238,040	5,035	20,674	1,177,849	4,790	19,669

	Santa Fe				Twin Rivers			
	CO2 Reductions (Tons)	NOx Reductions (Tons)	SO2 Reductions (Tons)	Hg Reductions (lbs)	CO2 Reductions (Tons)	NOx Reductions (Tons)	SO2 Reductions (Tons)	Hg Reductions (lbs)
Projected for a year	128,423	97	48	0.9	122,180	92	46	0.8

	Santa Fe				Twin Rivers			
	Projected Day Performance				Projected Day Performance			
Time of Day	Winter Peak Day (MW) (January)	Winter Average Day (MW) (January)	Summer Peak Day (MW) (August)	Summer Average Day (MW) (August)	Winter Peak Day (MW) (January)	Winter Average Day (MW) (January)	Summer Peak Day (MW) (August)	Summer Average Day (MW) (August)
1:00 AM	-	-	-	-	-	-	-	-
2:00 AM	-	-	-	-	-	-	-	-
3:00 AM	-	-	-	-	-	-	-	-
4:00 AM	-	-	-	-	-	-	-	-
5:00 AM	-	-	-	-	-	-	-	-
6:00 AM	-	-	-	-	-	-	-	-
7:00 AM	-	-	-	-	-	-	-	-
8:00 AM	-	0.1	3.4	3.0	0.4	0.1	4.9	4.6
9:00 AM	33.4	20.7	37.0	28.0	35.4	18.7	42.5	36.3
10:00 AM	64.3	38.5	63.7	48.7	61.4	35.8	61.8	48.7
11:00 AM	64.8	45.1	72.9	54.7	62.5	43.0	68.1	52.2
12:00 PM	62.6	45.2	73.4	59.9	59.7	43.4	56.9	53.4
1:00 PM	60.4	44.9	63.5	60.2	57.9	40.4	69.0	56.4
2:00 PM	60.3	48.1	67.6	56.8	58.4	39.5	61.6	55.9
3:00 PM	63.3	45.7	64.9	53.7	60.4	39.0	32.6	52.5
4:00 PM	64.6	47.3	9.5	50.6	61.7	39.6	11.0	52.2
5:00 PM	45.8	35.8	12.0	51.4	53.4	31.0	6.3	50.0
6:00 PM	2.5	5.1	14.1	44.2	9.6	5.3	3.8	41.5
7:00 PM	-	-	4.1	30.5	-	-	1.5	28.8
8:00 PM	-	-	0.7	4.7	-	-	0.3	7.5
9:00 PM	-	-	-	-	-	-	-	-
10:00 PM	-	-	-	-	-	-	-	-
11:00 PM	-	-	-	-	-	-	-	-
12:00 AM	-	-	-	-	-	-	-	-

All projected values were developed for use in Docket No. 20200245-EI (Santa Fe, Twin Rivers, Charlie Creek, Duette and Sandy Creek) to project the performance of the solar plant over a 30-year period. These values use historic years of location-specific, solar irradiance data to create a projected irradiance year, similar to the development of a "weather normal" year for load forecasting. These projected values are the best available data for the projection of long-term unit performance through the life cycle of the solar power plant but may or may not be realized in any specific calendar year or month.

Data is provided for the projected year 2021. Forecasted data for any specific future month or year will vary due to changes in anticipated solar plant performance including any plant in-service shakedown once placed in-service and changes in the total DEF system make up and performance.

In response to the table requesting Peak Day Performance, DEF has (1) adjusted the summer peak-day month to August consistent with DEF's projected summer peak; and (2) provided data for the specific day which aligns with the projected peak for each month as well as the more representative value of the average for the peak month.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20210007-EI EXHIBIT: 41
PARTY: Staff Exhibit 41
DESCRIPTION: DEF's response to Staff's Third Set of Interrogatories Nos. 4-6 Bates Nos. 00062-00068

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DEF's response to Staff's Third Set of Interrogatories Nos. 4-6

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause

Docket No. 20210007-EI

Dated: September 16, 2021

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO
STAFF'S THIRD SET OF INTERROGATORIES (NOS. 4-6)

Duke Energy Florida, LLC ("DEF"), responds to Staff's Third Set of Interrogatories to DEF (Nos. 4-6), as follows:

INTERROGATORIES

4. For the following questions, please refer to DEF witness Hill's direct testimony filed on July 30, 2021.

   a. Please refer to page 2, lines 14-16. Please identify the total cost of the reclassified invoices that were received in 2020, but not processed until 2021.

RESPONSE:

a. In our April 2021, "2020 DEF ECRC True Up" filing, we stated that the "costs associated with the Crystal River Landfill ditch remediation work were incorrectly recorded to a different project. This mischarge will be corrected in the 2021 financial results." The invoices were processed and paid, in 2020, to an incorrect project which was not a project that was included in the ECRC recoverable filing. The correction to move those costs out of the incorrect project was done in 2021. The total cost of the invoices that were recorded in 2020 and reclassified in 2021 was $319,221.01.

b. Please refer to page 3, lines 19-20. Witness Hill testified that Project 18 - CCR Ash Landfill Project will be completed in 2021.

i. Please explain if additional capital investments will be needed for Project 18 beyond 2021 and under the current Federal CCR Rule. If so, please identify the capital investments.

ii. Please explain if annual operation and maintenance (O&M) costs will be needed for Project 18 beyond 2021. If so, please identify the O&M costs.

RESPONSE:

i. DEF does not currently expect additional capital expenditures beyond 2021. If any additional capital expenditures become necessary as a result of the ongoing groundwater monitoring or other Federal CCR rule compliance requirements, DEF will update the Commission and provide the costs for recovery, as appropriate, in later ECRC filings.

ii. Various maintenance and repair work will continue beyond 2021 for the ash landfill to comply with the Federal CCR rule. These include maintenance of the landfill cover, vegetation management, fugitive dust mitigation, weekly and annual inspections and maintenance of the lined-sedimentation pond and perimeter ditch. DEF will also continue to perform the required groundwater monitoring, which includes engineering, sampling, analysis and reporting. The annual O&M costs for these tasks forecasted for 2022 O&M expenditures were filed with the Commission on August 27, 2021. DEF will continue to inform the Commission of annual O&M spending required to comply with the Federal CCR rule beyond 2022 in future ECRC filings.

5. For the following questions, please refer to DEF witness Anderson's direct testimony filed on July 30, 2021.

   a. Please refer to page 4, line 16. Witness Anderson stated that the cost variance for Project 7.4 - CAIR/CAMR CR-Energy (Conditions of Certification) Program was "primarily due to a decrease in the forecasted repairs."

      i. Please identify if the total number of forecasted repairs was lower or if the actual costs for each repair performed were lower than forecasted.

      ii. Please explain if the forecasted repairs were scheduled or unscheduled repairs that were anticipated by DEF.

RESPONSE:

i. This variance is primarily due to less-required maintenance than originally projected.

ii. DEF projects maintenance expenses based on operational experience. While maintenance may or may not be scheduled, a certain level of maintenance is to be expected, and therefore, included in projected O&M expense.

b. Please refer to page 4, line 22. Witness Anderson stated that the cost variance for Project 17 - MATS CR 4 & 5 was "primarily due to a decrease in the forecasted repairs."

i. Please identify if the total number of forecasted repairs was lower or if the actual costs for each repair performed were lower than forecasted.

ii. Please explain if the forecasted repairs were scheduled or unscheduled repairs that were anticipated by DEF.

RESPONSE:

i. This variance is primarily due to less-required maintenance than originally projected.

ii. DEF projects maintenance expenses based on operational experience. While maintenance may or may not be scheduled, a certain level of maintenance is to be expected, and therefore, included in projected O&M expense.

Duke Energy Florida, LLC
Docket No. 20210007-EI
Staff's Third Set of ROGs
Interrogatory No. 6

6. For the following question, please refer to DEF witness Dean's direct testimony filed on July 30, 2021, Exhibit GPD-3, page 7 of 27. Project 17x – Mercury & Air Toxics Standards (MATS). Please explain the 2.0 percent decrease in capital investment for this project.

RESPONSE:

The decrease between the original 2021 Projection as filed on August 28, 2020, in Docket 20200007-EI, and the updated forecasted total as filed in the Actual/Estimate schedules, filed on July 30, 2021, in Docket 20210007-EI, is primarily due to a lower rate of return utilized in the Actual/Estimate schedules.

In both filings, the prescribed methodologies approved in Order No. PSC-2020-0165-PAA-EU, Docket No. 20200118-EU, were used to calculate the Weighted Average Cost of Capital ("WACC"). However, due to the different methodologies prescribed for each filing, two different WACCs were calculated. The WACC for the original projection filing was calculated to be 7.92%. For the Actual/Estimate schedules, the WACC was calculated to be 7.80%.

Also, the Actual/Estimate filing used updated, property tax rates. The original Projection filing was based on 2019 property tax factors, and the Actual/Estimate used 2020 property tax factors, which were slightly lower.

There were no capital additions for 2021.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20210007-EI EXHIBIT: 42
PARTY: Staff Exhibit 42
DESCRIPTION: DEF's response to Staff's Fourth Set of Interrogatories Nos. 7-8 Bates Nos. 00069-00073

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DEF's response to Staff's Fourth Set of Interrogatories Nos. 7-8

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause

Docket No. 20210007-EI

Dated: October 05, 2021

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO
STAFF'S FOURTH SET OF INTERROGATORIES (NOS. 7-9)

Duke Energy Florida, LLC ("DEF"), responds to Staff's Fourth Set of Interrogatories to DEF (Nos. 7-9), as follows:

INTERROGATORIES

7. For the following questions, please refer to DEF witness McDaniel's direct testimony filed on August 27, 2021, page 4, lines 14-17.

   a. Please explain how the $20,000 estimate (which witness McDaniel stated would support consultations in the event the Florida Department of Environmental Protection requests additional information) was established.

   RESPONSE:

   The $20k estimate was based on a previous estimate from a consulting firm for similar work at another station. Due to the fact that the NPDES permit is not final and still under review by the Florida Department of Environmental Protection (FDEP) and permit requirements are therefore not yet established, it is unclear whether FDEP will request additional information or studies to supplement the source waterbody data, impingement or entrainment data, and/or any threatened or endangered species provided by DEF.

b. Please identify the operation and maintenance costs that were incurred in 2021 specific to Crystal River North and the work the costs supported.

RESPONSE:

In the August 27, 2021 Filing (2022 Projection), there were no 2021 costs included for the 316(b) projects. This filing represented only the 2022 projected costs, which did not anticipate any 2021 costs being carried over. However, as reflected in DEF's 2021 Actual/Estimated Filing, on July 30, 2021, there are no 2021 O&M costs specific to the Crystal River North 316(b) project.

Duke Energy Florida, LLC
Docket No. 20210007-EI
Staff's Third Set of ROGs
Interrogatory No. 8

8. Please refer to DEF witness McDaniel's direct testimony filed on August 27, 2021, page 7, lines 9-14. Please explain if the $75,000 projected for Project 8 - Arsenic Groundwater Standard Program will be solely for the continued implementation of the Natural Attenuation Monitoring Plan.

   a. If not, please list the other activities for Project 8 that the $75,000 will support.

   RESPONSE:

   As stated in Ms. McDaniel's August 27, 2021, testimony filed in Docket No. 20210007-EI, the $74k O&M expenditures projected for 2022 are associated with post-remediation, groundwater monitoring, implementation of a deed restriction and restrictive covenant for the affected area, final analysis and reporting of results to the agency, and monitoring well abandonment. Implementation of the Natural Attenuation Monitoring Plan is a portion of the post-remediation, groundwater monitoring.

9. Please refer to the July 2021 Solar Report filed on August 30, 2021, Document No. 09827-2021 for the following question. Please explain in detail the unusually low performance of the Lake Placid solar project for the month of July 2021.

RESPONSE:

DEF's Lake Placid Solar Power Plant is in a planned outage. The outage work scope includes coupling an advanced 17.275 MW / 34 MWh lithium-ion battery to the existing 45 MW solar photovoltaic facility.

This pilot project is described in DEF's 2021 Ten-Year Site Plan starting on pages 3 through 50 and shown in Table 3.3 on pages 3 through 51. This project is piloting how solar energy may be dispatched by the DEF grid operators. It is testing the technology's energy capture and peak load shaving capability. The outage is expected to continue into early 2022.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20210007-EI EXHIBIT: 43
PARTY: Staff Exhibit 43
DESCRIPTION: TECO's response to Staff's First Request for Production Nos. 1-2 (No. 1 has attachments) Bates Nos. ...

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TECO's response to Staff's First Request for Production Nos. 1-2

(No. 1 has attachments)

TAMPA ELECTRIC COMPANY
DOCKET NO: 20210007-EI
STAFF'S FIRST REQUEST FOR PRODUCTION OF DOCUMENTS
DOCUMENT NO. 1
BATES PAGES: 1-3
FILED: OCTOBER 14, 2021

1. Please refer to witness Sizemore's Exhibit MAS-4, filed October 1, 2021. Please provide an electronic copy of the schedules contained within Exhibit MAS-4 in Microsoft Excel format.

A. Please see Excel files "(BS 2) 2021 6+6 ECRC Act-Est True-Up - For Reg Baseline_.xlsx" and "(BS 3) Supp. 2 - Bayside 316 (b) Compliance Included, CETM Removed.xlsx".

TAMPA ELECTRIC COMPANY
DOCKET NO: 20210007-EI
STAFF'S FIRST REQUEST FOR PRODUCTION OF DOCUMENTS
DOCUMENT NO. 2
BATES PAGES: 4-5
FILED: OCTOBER 14, 2021

2. Please refer to TECO's October 1, 2021 filing. Please complete the summary table below by providing the return on equity (ROE), equity ratio, and depreciation rates used in both the original filing and as revised by the proposed 2021 Settlement Agreement.

	Original Filing	2021 Settlement Agreement
ROE		
Equity Ratio		
Depreciation Rate		

A. Please see the following table for the requested data.

	Original Filing	2021 Settlement Agreement
ROE	10.75%	9.95%
Equity Ratio	54%	54%
Depreciable Group and rate:		
311.40	2.9%	3.2%
311.45	2.0%	2.1%
311.51	4.1%	4.0%
311.52	3.5%	3.5%
311.53	3.1%	3.1%
311.54	2.4%	2.8%
312.40	3.4%	4.6%
312.41	4.0%	5.2%
312.42	3.7%	4.3%
312.43	3.5%	3.6%
312.44	3.0%	3.3%
312.45	2.5%	3.1%
312.46	3.3%	4.3%
312.51	4.3%	4.3%
312.52	4.0%	4.2%
312.53	3.9%	3.5%
312.54	3.8%	3.6%
315.40	3.7%	3.5%

Depreciable Group and rate (cont.):		
315.41	3.5%	4.4%
315.42	3.3%	5.0%
315.43	3.6%	3.3%
315.44	3.2%	2.9%
315.45	3.1%	2.4%
315.46	3.5%	3.5%
315.51	4.8%	4.0%
315.52	4.1%	3.7%
315.53	4.0%	3.2%
315.54	3.9%	2.8%
316.40	4.2%	3.3%
316.51	4.1%	4.0%
316.52	3.7%	3.4%
316.53	3.4%	2.9%
316.54	3.3%	2.4%
341.80	2.2%	3.1%
342.81	3.4%	4.1%
345.81	3.3%	3.3%
395.00	14.3%	14.3%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20210007-EI EXHIBIT: 44
PARTY: Staff Exhibit 44
DESCRIPTION: TECO's response to Staff's Third Set of Interrogatories Nos. 3-13 Bates Nos. 00078-00091

44

TECO's response to Staff's Third Set of Interrogatories Nos. 3-13

TAMPA ELECTRIC COMPANY
DOCKET NO. 20210007-EI
STAFF'S THIRD SET OF INTERROGATORIES
INTERROGATORY NO. 3
BATES PAGES:1-2
FILED: JUNE 1, 2021

Please refer to TECO witness Sizemore's direct testimony filed April 1, 2021, page 6 through page 10, for questions 3 through 5.

3. For each project listed below, please explain why operating on natural gas instead of coal reduced the project's operation and maintenance (O&M) costs.

a. Big Bend Unit 3 Flue Gas Desulfurization Integration

b. Big Bend Units 1 & 2 FGD

c. Big Bend PM Minimization and Monitoring

d. Big Bend NOx Emission Reduction

e. Big Bend Unit 2 Pre-SCR

f. Big Bend Unit 3 Pre-SCR

g. Big Bend Unit 2 SCR

h. Big Bend Unit 3 SCR

i. Big Bend Gypsum Storage Facility

A. a. When any unit is combusting coal, the station's air permits require SO_2 pollution control equipment be operating. The flue gas desulfurization system for the unit processes limestone into a slurry to inject into the scrubber tower, the resulting stack gases are scrubbed of SO_2 and the byproduct from the process is gypsum. The gypsum is then processed by a separate system. In addition to the limestone and gypsum processing, wastewater treatment is required to treat the water to meet permit discharge limitations. When combusting natural gas, which has virtually no SO_2, the expenses are significantly reduced. Because the flue gases still flow through the scrubber system, the infrastructure still needs to be maintained to protect the duct work and stacks.

Big Bend Unit 3 did not combust coal in 2020, thus reducing the O&M FGD costs.

b. Please see Tampa Electric's response to Staff's Third Set of Interrogatories, No. 3(a), above. Additionally, Units 1 and 2 did not combust coal in 2020, thus reducing the O&M FGD costs.

c. When any of the station's units are not combusting coal, there is virtually no particulate matter generated. The ability to fire coal in Big Bend Units 1 and 2 was eliminated in late 2018 and Big Bend Unit 3, although permitted to combust both coal and natural gas, did not combust coal in 2020, thus significantly reducing O&M costs associated with treatment and handling costs related to particulate matter permit compliance. Big Bend Unit 4 continues to combust coal; however, Big Bend Unit 4 has the flexibility to combust either natural gas, at reduced loads, and coal. Big Bend Unit 4 can also co-fire natural gas with coal. Combusting natural gas and co-firing coal with natural gas reduces the amount of particulate matter. Big Bend Unit 4 combusted both coal and gas in 2020.

d. Big Bend Station continues to operate the NO_x pollution control systems on each of the units, regardless of whether combusting coal or natural gas. Although NO_x emissions from generating with natural gas are reduced when compared to generating with coal, the NO_x pollution control equipment must still be maintained. In 2020, reduced generation also contributed to reduced NO_x compliance costs.

e. Please see Tampa Electric's response to Staff's Third set of Interrogatories, No. 3(d), above.

f. Please see Tampa Electric's response to Staff's Third set of Interrogatories, No. 3(d), above.

g. Please see Tampa Electric's response to Staff's Third set of Interrogatories, No. 3(d), above.

h. Please see Tampa Electric's response to Staff's Third set of Interrogatories, No. 3(d), above.

i. Gypsum is generated when the Big Bend Station Units are combusting coal and the FGD system is in service. Because Units 1, 2, and 3 did not combust coal in 2020 and Unit 4 burned less coal than it had in previous years, O&M costs associated with the gypsum storage area has decreased.

4. Please explain why the Big Bend units were operated on less coal than projected.

A. Big Bend Units 1 and 2 air compliance permits were modified to allow only natural gas combustion in preparation for the retirement of Unit 2 and construction of the Unit 1 Modernization project. Big Bend 3 also only combusted natural gas in 2020 as the cost of natural gas was the most economic alternative throughout the period.

Major outages in 2020 contributed to less generation and overall coal usage on Big Bend Unit 4. In addition, outage durations were extended due to workforce issues associated with COVID-19.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20210007-EI
STAFF'S THIRD SET OF INTERROGATORIES
INTERROGATORY NO. 5
BATES PAGES:4-5
FILED: JUNE 1, 2021

5. Please complete the tables below by providing the 2020 projected vs. actual fuel consumption, fuel cost, and energy production for Big Bend Units 1, 2, and 3.

2020 Big Bend Fuel Consumption – Projected vs. Actual				
	Coal (insert units)		Natural Gas (insert units)	
Big Bend Unit	Projected	Actual	Projected	Actual
1				
2				
3				

2020 Big Bend Fuel Cost – Projected vs. Actual				
	Coal ($)		Natural Gas ($)	
Big Bend Unit	Projected	Actual	Projected	Actual
1				
2				
3				

2020 Big Bend Energy Production – Projected vs. Actual				
	Coal (MWh)		Natural Gas (MWh)	
Big Bend Unit	Projected	Actual	Projected	Actual
1				
2				
3				

A. Please see the tables below for the 2020 projected versus actual consumption, fuel cost, and energy production.

2020 Big Bend Fuel Consumption – Projected vs. Actual				
Big Bend	Coal (insert units)		Natural Gas (insert units)	
Unit	Projected	Actual	Projected	Actual
1	0	0	2,185,570	842,929
2	0	0	3,994,250	8,539,480
3	0	0	6,576,950	14,444,355

TAMPA ELECTRIC COMPANY
DOCKET NO. 20210007-EI
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2020 Big Bend Fuel Cost – Projected vs. Actual				
Big Bend Unit	Coal ($)		Natural Gas ($)	
	Projected	Actual	Projected	Actual
1	0	0	8,059,071	2,403,261
2	0	0	14,809,333	28,101,459
3	0	0	25,015,602	42,872,463

2020 Big Bend Energy Production – Projected vs. Actual				
Big Bend Unit	Coal (MWh)		Natural Gas (MWh)	
	Projected	Actual	Projected	Actual
1	0	0	174,890	54,568
2	0	0	357,140	704,018
3	0	0	607,790	1,260,598

TAMPA ELECTRIC COMPANY
DOCKET NO. 20210007-EI
STAFF'S THIRD SET OF INTERROGATORIES
INTERROGATORY NO. 6
BATES PAGE:6
FILED: JUNE 1, 2021

6. Please refer to TECO witness Sizemore's direct testimony filed April 1, 2021, page 7, lines 17 through 20, Bayside SCR Consumables. Please explain why ammonia use increases during the summer.

A. Ammonia is used to reduce NO_x emissions, which are a byproduct of combustion. Demand increases in the summer months due to increased generation, which is attributed to the warmer weather. The increased generation drives increased combustion, and therefore NO_x emissions. As a result, ammonia consumption increases in order to continue to reduce NO_x emissions to acceptable levels.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20210007-EI
STAFF'S THIRD SET OF INTERROGATORIES
INTERROGATORY NO. 7
BATES PAGE:7
FILED: JUNE 1, 2021

7. Please refer to TECO witness Sizemore's direct testimony filed April 1, 2021, page 8, lines 11 through 15, Clean Water Act Section 316(b) Phase II Study.

a. Please explain if the permit delay will increase O&M costs in 2021.

b. Please explain if the permit delay will impact the project's total capital or O&M costs. If so, please provide the estimated net difference.

A. a. The expenditures incurred are dependent upon when the NPDES permit is received. If the permit is received earlier in the year, there may be an increase in O&M costs in 2021 due to expenditures that are required by the compliance schedule in the permit. If the permit is not received until late 2021, there will be no increased O&M costs in 2021. The permit delay is not anticipated to increase total O&M costs of the project.

b. The permit delay is not anticipated to impact the overall capital or O&M costs, but it will delay the incurrence of the costs.

8. Please refer to TECO witness Sizemore's direct testimony filed April 1, 2021, page 8, lines 17 through 24, Arsenic Groundwater Standard Program. Please provide the total amount inadvertently charged to the project for the replacement well.

A. The total amount inadvertently charged to the project for the replacement well was $21,151.38.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20210007-EI
STAFF'S THIRD SET OF INTERROGATORIES
INTERROGATORY NO. 9
BATES PAGE:9
FILED: JUNE 1, 2021

9. Please refer to TECO witness Sizemore's direct testimony filed April 1, 2021, page 10, lines 3 through 8, Big Bend Coal Combustion Residuals (CCR) Rule. Please explain what the associated activity costs were for.

A. The costs associated with the CCR rule were related to removal of CCRs (slag and ash) from the east coalfield pond and installation of a geosynthetic liner in the pond. Also included in the costs were removal of CCR (gypsum) material from stormwater conveyances associated with the north gypsum stackout area.

10. Please refer to TECO witness Sizemore's direct testimony filed April 1, 2021, page 10, lines 10 through 13, Big Bend CCR Rule Phase II.

a. Please explain what the project disposal activities are.

b. Please explain the cause of the project delays.

c. Please explain if the project delays will impact the project's total capital or O&M costs. If so, please provide the estimated net difference.

A. a. Project costs resulting from disposal activities include dewatering, drying, and excavation of CCR material contained in the impoundment, loading trucks for transport, and finally disposal of material in an approved offsite landfill.

b. Contributions to project delays included delay in finalization of landfill disposal contracts, weather delays during the rainy season, additional unanticipated dewatering activities and also the inability of transporters to keep pace with the amount of material being excavated for disposal.

c. These delays will not result in an increase in the total project and O&M costs. However, the costs will be incurred at a later date.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20210007-EI
STAFF'S THIRD SET OF INTERROGATORIES
INTERROGATORY NO.11
BATES PAGE:11
FILED: JUNE 1, 2021

Capital

11. Please refer to TECO witness Sizemore's direct testimony filed April 1, 2021, page 10, lines 3 through 8 and lines 21 through 25, Big Bend CCR Rule. Please reconcile the increased O&M costs due to project acceleration versus the decreased capital costs due to project delays.

A. There was no acceleration of the project. This project was scheduled to be completed in 2019 but due to excessive rainfall, some of the project's O&M activity related to removal and offsite disposal was delayed until 2020. The O&M costs in 2020 were higher as a result. Capital project components were delayed due to having to extend the time to remove the additional CCR material and also due to project weather delays, pushing out some capital costs from 2020 into 2021.

12. Please refer to TECO witness Sizemore's direct testimony filed April 1, 2021, page 10, lines 21 through 25, Big Bend CCR Rule.

a. Please explain the cause of the project delays.

b. Please explain if the project delays will impact the project's total capital or O&M costs. If so, please provide the estimated net difference.

A. a. The project delays were a result of the following: project design taking longer than expected, excessive rainfall delays, and additional dewatering needed prior to removal.

b. The project delays are not anticipated to impact the overall capital or O&M costs. However, it will delay the incurrence of the costs.

13. Please refer to TECO witness Sizemore's direct testimony filed April 1, 2021, page 11, lines 10 through 18, Big Bend ELG Compliance. Please explain if the project delays will impact the project's total capital or O&M costs. If so, please provide the estimated net difference.

A. The project delays are not anticipated to impact the overall capital or O&M costs. However, they will impact the timing of costs incurred.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20210007-EI EXHIBIT: 45
PARTY: Staff Exhibit 45
DESCRIPTION: TECO’s response to Staff's Fourth Set of Interrogatories No. 14 Bates Nos. 00092-00093

45

TECO’s response to Staff's Fourth Set of Interrogatories No. 14

TAMPA ELECTRIC COMPANY
DOCKET NO: 20210007-EI
STAFF'S FOURTH SET OF INTERROGATORIES
INTERROGATORY NO. 14
BATES PAGES:
FILED: JUNE 28, 2021

14. Please refer to TECO's response to Staff's Third Set of Interrogatories, No. 5. Please provide the unit for the quantity of natural gas consumption, used in the first table of the Utility's response.

A. The unit of measure for the quantity of natural gas consumption used in Tampa Electric's response to Staff's Third Set of Interrogatories No. 5, table one, is Mcf.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20210007-EI EXHIBIT: 46
PARTY: Staff Exhibit 46
DESCRIPTION: TECO's response to Staff's Fifth Set of Interrogatories Nos. 15-17 Bates Nos. 00094-00099

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TECO's response to Staff's Fifth Set of Interrogatories Nos. 15-17

TAMPA ELECTRIC COMPANY
DOCKET NO: 20210007-EI
STAFF'S FIFTH SET OF INTERROGATORIES
INTERROGATORY NO. 15
BATES PAGES: 1-2
FILED: SEPTEMBER 16, 2021

15. Please refer to witness Sizemore's actual-estimated testimony filed on July 30, 2021, page 6, lines 9 through 12, for the following questions (SO2 Emissions Allowances).

a. Please explain why there were more cogeneration purchases than originally projected.

b. Please explain how cogeneration purchases impact the SO2 emission costs TECO is responsible for.

c. Please identify both the SO2 emission allowance rate used in the original projection and the rate used in the actual-estimated filing.

A. a. Cogen purchases projected for 2021 were based on the monthly average of the actual cogeneration purchased during the first half of 2020, annualized for a full year. Cogeneration purchases in the 2021 Act-Est were based on six months of actual 2021 cogeneration purchases, and six months reforecasted using the average of the first six months of actual data. Cogeneration purchases during the first half of 2021 were higher than in the first half of 2020, resulting in a higher reforecast than originally projected.

b. The acid rain control title of the CAAA sets forth a comprehensive regulatory mechanism designed to control acid rain by limiting sulfur dioxide (SO_2) emissions by electric utilities. For each ton of SO_2 emitted, utilities consume one allowance. EPA issues allowances to utilities at no cost, or they can be purchased in the allowance marketplace. The weighted value of these allowances consumed is passed through the ECRC. Additionally, payments made to cogenerators at the marketplace value for allowances are expensed through this project because the cogeneration purchases avoid company use of additional allowances.

c. As can be seen on Form 42 – 4E, SO_2 Emissions Allowances in columns (1) and (2) are made up of Tampa Electric generating unit SO_2 Allowance consumption less Cogen SO_2 Allowances (related to purchases from cogenerators). The $15 projected for 2021 shown in column (2) was based on 6 months of prior year actual Tampa Electric generation unit SO_2 Allowance consumption less Cogen Purchases, annualized for a full year. The $41 reforecast for the 2021 Actual / Estimate shown in column (1) was based on actual Tampa Electric generation unit SO_2 Allowance consumption and Cogen purchases booked the first six months of 2021, annualized for the remainder of the year. Cogenerator purchases for the first half of 2021 were higher than in the first half of 2020, resulting in a higher reforecast than originally projected.

TAMPA ELECTRIC COMPANY
DOCKET NO: 20210007-EI
STAFF'S FIFTH SET OF INTERROGATORIES
INTERROGATORY NO. 16
BATES PAGES: 3-4
FILED: SEPTEMBER 16, 2021

16. Please refer to witness Sizemore's actual-estimated testimony filed on July 30, 2021, page 6, lines 16 through 19, and TECO's response to Staff's Third Set of Interrogatories, No. 3, for the following questions (Big Bend Units 1 & 2 FGD).

a. Please explain if there are any regulations that require flue gas desulfurization (FGD) for the combustion of natural gas.

i. If no, please explain if it is technically possible to bypass the FGD system while combusting natural gas.

b. Please explain why TECO assumed it would not be necessary to operate the FGD system while combusting natural gas.

c. Please explain how the "system ductwork" is connected to the FGD system (e.g., upstream, downstream, self-contained, separate system, etc.).

d. Please explain how and why the FGD system is needed to protect system ductwork, when "virtually no particulate matter is generated when combusting natural gas."

e. Please provide both the estimated annual cost of operating the FGD system when generating by natural gas and when the units had previously generated by coal.

f. Please explain why only Unit 2 is required to operate the FGD system, when Big Bend Units 1 and 3 were generating by natural gas as well.

A. a. No. There are not any regulations that require flue gas desulfurization ("FGD") while combusting natural gas; however, it is necessary to operate the FGD system to allow the flue gas to exit the system.

i. Please see Tampa Electric's response to Interrogatory No. 16(a), above.

b. Tampa Electric assumed that the FGD system would still be operating; however, the company assumed minimal costs as the unit would not be combusting coal.

c. The system ductwork connects the boiler to the selective catalytic reduction ("SCR") and electrostatic precipitator and then connects to the scrubber tower. The scrubber is the last piece of pollution control equipment prior to the stack.

d. When combusting natural gas, which has virtually no SO_2, FGD operating expenses are significantly lower than when combusting coal. Because the flue gases flow through the scrubber system regardless of combustion fuel type, the infrastructure will continue to require maintenance to protect the duct work and stacks.

e. The average FGD costs while running Big Bend Station units primarily on coal was approximately $1.25 million per year, based on the period 2015 through 2017. The average FGD costs for operating Big Bend Station units on primarily natural gas is approximately $25,000 per year, based on the period 2020 through 2021. For years 2018 and 2019, the Big Bend Station units generated energy using a mix of both coal and gas.

f. Tampa Electric's response to Staff's Third Set of Interrogatories, No. 3(b) pertained to the Big Bend Units 1 & 2 FGD system. Units 1 & 2 use one FGD system, and Units 3 & 4 share a second FGD system. The Unit 3 & 4 FGD system was used when Unit 3 burned natural gas.

TAMPA ELECTRIC COMPANY
DOCKET NO: 20210007-EI
STAFF'S FIFTH SET OF INTERROGATORIES
INTERROGATORY NO. 17
BATES PAGE: 5
FILED: SEPTEMBER 16, 2021

17. Please refer to witness Sizemore's actual-estimated testimony filed on July 30, 2021, page 9, lines 17 through 20. For each Big Bend unit, please identify both the date when TECO first anticipated operating the unit on natural gas, and the date when the unit actually began operating on natural gas.

A. Tampa Electric added natural gas capability to Big Bend Units 1-4 through the initial igniter conversions in 2015 and then, in 2017, increased the units' natural gas capacities by adding more natural gas burners to Big Bend Units 1, 2, and 3 so that those units could operate close to the maximum dependable capacity (MDC) on natural gas. They operated as dual fuel units based on economics. In April 2018, as part of the Big Bend Modernization project, Tampa Electric applied for a permit to modernize Unit 1, and retire Unit 2. In its Florida Department of Environmental Protection (FDEP) Air Construction Permit application, Tampa Electric stated its intention to cease coal combustion operations at Big Bend Unit 1 once the Modernization project construction began, and to retire Big Bend Unit 2. Big Bend Units 1 and 2 have operated on natural gas for economic reasons since 2017. Big Bend Unit 3 has been operating on natural gas based on economics and operational efficiency since 2018, and will be retired in 2023. Big Bend Unit 4 can operate on natural gas or coal and currently burns coal for economic and operational reasons.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20210007-EI EXHIBIT: 47
PARTY: Staff Exhibit 47
DESCRIPTION: TECO's response to Staff's Sixth Set of Interrogatories Nos. 18-24 Bates Nos. 00100-00107

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TECO's response to Staff's Sixth Set of Interrogatories Nos. 18-24

TAMPA ELECTRIC COMPANY
DOCKET NO: 20210007-EI
STAFF'S SIXTH SET OF INTERROGATORIES
INTERROGATORY NO. 18
BATES PAGE: 1
FILED: OCTOBER 5, 2021

18. Please refer to witness Sizemore's direct testimony filed on August 27, 2021, page 3, lines 4 through 16, and page 5, lines 10 through 15. Please explain if and when TECO will provide revised testimony and/or exhibits to reflect the Bayside Section 316(b) program and/or the proposed 2021 Agreement.

A. On October 1, 2021, Tampa Electric filed its revised 2022 Projection Exhibit, MAS-4, reflecting the inclusion of the proposed 2021 Agreement and the Bayside Section 316(b) Compliance project, that was approved by the Commission on September 8, 2021, and memorialized in Order No. PSC-2021-0356-PAA-EI, issued on September 15, 2021.

TAMPA ELECTRIC COMPANY
DOCKET NO: 20210007-EI
STAFF'S SIXTH SET OF INTERROGATORIES
INTERROGATORY NO. 19
BATES PAGE: 2
FILED: OCTOBER 5, 2021

19. Please refer to witness Sizemore's direct testimony filed on August 27, 2021, page 3, lines 8 through 13. Please explain in detail the impact of the proposed 2021 Agreement on ECRC recovery. As part of your response, please indicate if the 2021 Agreement will impact true-up recovery for the current period of January 2021 through December 2021 and explain how.

A. As referred to in the testimony of M. Ashley Sizemore, certain terms of the company's proposed 2021 Agreement will have an impact on the 2022 ECRC factors. Specific changes include: 1) the return on equity adjustment; 2) updated Tax Expansion Factor; 3) the transfer of the net book value, as of December 31, 2021, from ECRC to the Clean Energy Transition Mechanism ("CETM") for the following Assets being retired: portions of Big Bend Units 1 & 2 FGD and the entirety of Big Bend Units 1, 2 and 3 SCRs; 4) implementation of the new depreciation rates from the company's recent depreciation study and, 5) updated cost allocation and rate design.

As noted in Tampa Electric's response to Interrogatory No 18, above, the Bayside 316(b) Compliance project is included in the October 1, 2021 filing.

The 2021 Agreement will be effective January 1, 2022. The January 2021 through December 2021 period true-up amount will not be affected by the 2021 Agreement. However, the 2021 true-up amount will be recovered during 2023, and will be included in the total amount recovered, which is governed by the 2021 Agreement factor calculation methodology described in the company's October 1, 2021 filing referenced in the response to Interrogatory No. 18.

TAMPA ELECTRIC COMPANY
DOCKET NO: 20210007-EI
STAFF'S SIXTH SET OF INTERROGATORIES
INTERROGATORY NO. 20
BATES PAGE: 3
FILED: OCTOBER 5, 2021

20. Please refer to witness Sizemore's direct testimony filed on August 27, 2021, page 7, lines 13 through 19. Please identify the revised total capital costs including the Bayside Section 316(b) program, both including and excluding impacts of the 2021 Agreement.

A. Please see the table below for the revised total capital project costs to be recovered through the environmental cost recovery clause.

Capital Costs without 2021 Agreement	Capital Costs with the 2021 Agreement
$46,842,960	$21,927,947

21. Please refer to witness Sizemore's direct testimony filed on August 27, 2021, page 9, lines 7 through 12. Please identify the revised total operation and maintenance (O&M) costs including the Bayside Section 316(b) program, both including and excluding impacts of the 2021 Agreement.

A. There are no changes to the projected 2022 O&M costs from the August 27, 2021 filing when the Bayside Section 316(b) program and the 2021 Agreement are considered. The O&M costs remain at $4,414,497. This is due to Bayside 316(b) not incurring any O&M costs until after the project is placed in service, after 2022.

TAMPA ELECTRIC COMPANY
DOCKET NO: 20210007-EI
STAFF'S SIXTH SET OF INTERROGATORIES
INTERROGATORY NO. 22
BATES PAGE: 5
FILED: OCTOBER 5, 2021

22. Please refer to witness Sizemore's direct testimony filed on August 27, 2021, page 9, line 21 through page 10, line 2.

a. Please identify the revised total jurisdictional costs for 2022 including the Bayside Section 316(b) program, both including and excluding impacts of the 2021 Agreement.

b. Please explain the discrepancy between the $51,072,871 total provided on page 10, line 2, and the $51,125,303 total provided in Form 42-1P.

A. a. Please see the table below for the revised total jurisdictional costs to be recovered through the environmental cost recovery clause.

Total Jurisdictional costs without 2021 Agreement	Total Jurisdictional costs with the 2021 Agreement
$51,257,457	$26,342,444

b. The $51,072,871 provided on Line 1(c), represents the total jurisdictional revenue requirement for the 2022 period prior to any adjustments and revenue tax factor applications. The $51,125,303, as shown on Form 42-1P, Line 4 represents the total jurisdictional revenue requirement once the 2020 final true-up over-recovery of $4,237,191 and the 2021 estimated under-recovery of $4,289,623 are included in the 2022 revenue requirement calculations, prior to the application of the revenue tax factor.

TAMPA ELECTRIC COMPANY
DOCKET NO: 20210007-EI
STAFF'S SIXTH SET OF INTERROGATORIES
INTERROGATORY NO. 23
BATES PAGE: 6
FILED: OCTOBER 5, 2021

23. Please refer to witness Sizemore's direct testimony filed on August 27, 2021, page 11, lines 1 through 14. Please identify the revised recovery factors including the Bayside Section 316(b) program, both including and excluding impacts of the 2021 Agreement.

A. The recovery factors requested are as follows:

2022 ECRC Projection - Recovery Factors Including Bayside 316(b):

Rate Class	(¢/kWh)
RS	0.264
GS, CS	0.261
GSD, SBF	
Secondary	0.255
Primary	0.253
Transmission	0.250
IS	
Secondary	0.247
Primary	0.245
Transmission	0.242
LS1	0.240
Total	0.260

2022 ECRC Projection - Recovery Factors Including Bayside 316(b) and 2021 Agreement:

Rate Class	(¢/kWh)
RS	0.138
GS, CS	0.135
GSD, SBF	
Secondary	0.130
Primary	0.129
Transmission	0.128
GSLDPR	0.123
GSLDSU	0.120
LS1, LS2	0.113
Total	0.133

24. Please refer to witness Burrows' direct testimony filed on August 27, 2021, page 13, lines 20 through 24. Does TECO project any capital or O&M expenditures prior to December 2021? If yes, how will TECO recover those costs?

A. Tampa Electric expects to incur approximately $950,000 in capital costs for the Bayside 316(b) Compliance project in 2021. No O&M costs are anticipated until the project's in-service date, after 2022. The company will include these costs in its 2021 true-up, to be filed in early 2022.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20210007-EI EXHIBIT: 48
PARTY: Staff Exhibit 48
DESCRIPTION: TECO's response to Staff's Seventh Set of Interrogatories No. 25 Bates Nos. 00108-00109

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TECO's response to Staff's Seventh Set of Interrogatories No. 25

TAMPA ELECTRIC COMPANY
DOCKET NO: 20210007-EI
STAFF'S SEVENTH SET OF INTERROGATORIES
INTERROGATORY NO. 25
BATES PAGE: 1
FILED: OCTOBER 14, 2021

25. Please refer to TECO's October 1, 2021 filing.

a. Please identify the witness sponsoring the summary explaining the methodology utilized to calculate the revised cost recovery factors.

b. Please refer to subparagraph 3. Explain why no change to the allocation methodology is made if the increment is negative.

A. a. The witness sponsoring the summary is M. Ashley Sizemore, Manager, Rates, in the Regulatory Affairs Department.

b. The 2021 Agreement specifies that the allocation factors will be applied to clauses that recover costs for plant investment in the same manner they were for the base revenues. These allocation factors were applied to increases in the revenue requirement. Therefore, only positive incremental values will be affected by the negotiated allocation factors.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20210007-EI EXHIBIT: 49
PARTY: Staff Exhibit 49
DESCRIPTION: Letter from Malcolm Means/TECO dated 10/1/21, With Attached 2022 Cost Recovery Factors Document No:...

49

Letter from Malcolm Means/TECO dated 10/1/21, With Attached 2022 Cost Recovery Factors

AUSLEY & MCMULLEN

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October 1, 2021

ELECTRONIC FILING

Mr. Adam J. Teitzman
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Docket 20210007-EI, Environmental Cost Recovery Clause

Dear Mr. Teitzman:

Attached for filing on behalf of Tampa Electric in the above-referenced docket are 2022 cost recovery factors prepared using the methodology agreed to by the parties in Paragraph 6 of the unanimous 2021 Stipulation and Settlement Agreement ("2021 Agreement") filed in Docket No. 20210034-EI on August 6, 2021. *See* FPSC Document No. 08857-2021. The company updated the clause factors using the same methodology used to prepare the 2022 base rates, which is consistent with (1) the general practice that clause factors reflect the cost of service/revenue allocations and rate design in the company's most recent rate case and (2) paragraph 6 of the 2021 Agreement. The Commission is currently scheduled to conduct a hearing regarding the 2021 Agreement on October 21, 2021. These factors are submitted in this docket for the Commission's review and approval if the Commission approves the 2021 Agreement at the October 21st hearing.

Included in this filing are:

1. A summary explaining the methodology utilized to calculate the revised cost recovery factors.
2. Proposed 2022 ECRC Cost Recovery Factors developed utilizing the 2021 Agreement methodology.
3. Schedules supporting the Proposed 2022 ECRC Cost Recovery Factors.

Sincerely,

Malcolm N. Means

Malcolm N. Means

Enclosures
cc: All Parties of Record (w/enclosures)

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing cost recovery factors, on behalf of Tampa Electric Company, have been furnished by electronic mail on this 1st day of October 2021 to the following:

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Malcolm N. Means

ATTORNEY

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

Per the 2021 Settlement Agreement ("2021 Agreement"), Tampa Electric must apply the same methodology used to allocate revenue to base revenues, as shown in Exhibit K to the agreement, to its 2022 clause factors that recover plant investments. Thus, the method should be applied to the Storm Protection Plan, Energy Conservation, and Environmental cost recovery clauses. The remaining two cost recovery clauses, Fuel and Capacity, do not recover costs for plant investment.

Exhibit K applies negotiated percentages to the base revenue increase to determine the revenue to be collected from the rate classes.

For the Environmental cost recovery factors, Tampa Electric determined the clause revenue increase for 2022 as described below.

1. Determine the 2021 baseline amount to be used to calculate the 2022 revenue increase.
    a. The 2021 baseline is set by taking the 2021 actual and estimated costs submitted on July 30, 2021 and applying the 2021 Agreement ROE and equity ratio to determine the baseline cost recovery amount. Project costs for assets to be retired and recovered through the CETM were removed.
    b. The calculation of revenues by rate class is conducted using the allocation methodology from the company's prior base rate case.
    c. The total revenue amount of this calculation is the revenue baseline to be used to determine 2022 and future years' increased costs.
2. Determine the 2022 (or future year) total revenue to be collected. This calculation is determined using the 2021 Agreement ROE, equity ratio, and depreciation rates. [1]
3. Subtract the 2021 revenue baseline amount determined in 1. from the 2022 (or future year) total revenue to be collected.
    a. If the increment is negative, no changes to the allocation methodology are made, i.e., the prior base rate case allocation method is used to allocate all revenue by class.
    b. If the increment is positive, the Exhibit K allocation factors are applied to the increment to determine the class revenue allocation. A positive class allocation amount is added to the 2021 baseline revenue amount, also by class, to determine the total revenue to be collected by class.
4. The 2022 billing determinants are used to calculate the 2022 clause cost recovery factors by dividing the total revenue by class determined in 3. by the appropriate class billing determinant.

The company is providing the accompanying detailed schedules demonstrating the calculations of these amounts for 2022. For future years, only the summary of the 2021 baseline amounts by class will be required, since they do not change.

[1] The Bayside 316(b) project is included in 2022 factors per the Commission's approval of this project on September 8, 2021.

EXHIBIT TO THE TESTIMONY OF
M. ASHLEY SIZEMORE

DOCUMENT NO. 1

TAMPA ELECTRIC'S ENVIRONMENTAL COST RECOVERY

PROJECTION

JANUARY 2022 THROUGH DECEMBER 2022

FORMS 42-1P THROUGH 42-8P

DOCKET NO. 20210007-EI
EXHIBIT NO. MAS-4, FORM 42-1P
DOCUMENT NO. 1, PAGE 1 OF 1
FILED: 10/01/2021

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to Be Recovered

Form 42 - 1P

For the Projected Period
January 2022 to December 2022

Line	Energy ($)	Demand ($)	Total ($)
1. Total Jurisdictional Revenue Requirements for the projected period			
a. Projected O&M Activities (Form 42-2P, Lines 7, 8 & 9)	$4,332,767	$81,730	$4,414,497
b. Projected Capital Projects (Form 42-3P, Lines 7, 8 & 9)	17,518,159	4,409,788	21,927,947
c. Total Jurisdictional Revenue Requirements for the projected period (Lines 1a + 1b)	21,850,926	4,491,518	26,342,444
2. True-up for Estimated Over/(Under) Recovery for the current period January 2021 to December 2021 (Form 42-2E, Line 5 + 6 + 10)	(4,161,856)	(127,767)	(4,289,623)
3. Final True-up for the period January 2020 to December 2020 (Form 42-1A, Line 3)	4,199,464	37,727	4,237,191
4. Total Jurisdictional Amount to Be Recovered/(Refunded) in the projection period January 2022 to December 2022 (Line 1 - Line 2- Line 3)	21,813,318	4,581,558	26,394,876
5. Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier)	$21,829,024	$4,584,857	$26,413,881

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

O&M Activities
(in Dollars)

Line		Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	Description of O&M Activities															
	a. Big Bend Unit 3 Flue Gas Desulfurization Integration	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	c. SO_2 Emissions Allowances	(5)	7	7	(5)	7	7	(5)	7	7	(5)	7	7	41		41
	d. Big Bend Units 1 & 2 FGD	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	e. Big Bend PM Minimization and Monitoring	21,630	21,630	21,630	21,630	21,630	21,630	21,630	21,630	21,630	21,630	21,630	21,630	259,560		259,560
	f. Big Bend NO_x Emissions Reduction	174	174	174	174	174	174	174	174	174	174	174	174	2,089		2,089
	g. NPDES Annual Surveillance Fees	0	34,500	0	0	0	0	0	0	0	0	0	0	34,500	$34,500	
	h. Gannon Thermal Discharge Study	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	i. Polk NO_x Emissions Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	j. Bayside SCR and Ammonia	10,200	10,200	11,500	12,500	14,000	15,200	15,200	15,300	14,000	12,500	10,200	10,200	151,000		151,000
	k. Big Bend Unit 4 SOFA	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	l. Big Bend Unit 1 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	m. Big Bend Unit 2 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	n. Big Bend Unit 3 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	o. Clean Water Act Section 316(b) Phase II Study	5,000	0	0	0	2,575	2,575	0	0	0	0	0	0	10,150	10,150	
	p. Arsenic Groundwater Standard Program	3,090	3,090	3,090	3,090	3,090	3,090	3,090	3,090	3,090	3,090	3,090	3,090	37,080	37,080	
	q. Big Bend 1 SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	r. Big Bend 2 SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	s. Big Bend 3 SCR	20,928	9,136	43,640	9,136	35,926	25,553	26,808	30,500	33,748	64,667	43,844	28,637	372,522		372,522
	t. Big Bend 4 SCR	126,564	138,356	103,851	138,356	111,565	121,939	120,683	116,991	113,744	82,825	103,647	118,855	1,397,376		1,397,376
	u. Mercury Air Toxics Standards	0	0	2,000	0	0	0	0	0	0	0	0	0	2,000		2,000
	v. Greenhouse Gas Reduction Program	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	w. Big Bend Gypsum Storage Facility (East 40)	101,103	101,103	101,103	101,103	101,103	101,103	101,103	101,103	101,103	101,103	101,103	101,103	1,213,236		1,213,236
	x. Coal Combustion Residuals (CCR) Rule - Phase I	77,500	77,500	77,500	77,500	77,500	77,500	77,500	77,500	77,500	77,500	77,500	77,500	930,000		930,000
	y. Big Bend ELG Compliance	412	412	412	412	412	412	412	412	412	412	412	412	4,944		4,944
	z. Coal Combustion Residuals (CCR) Rule - Phase II	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	aa. Big Bend Unit 1 Sec. 316(b) Impingement Mortality	0	0	0	0	0	0	0	0	0	0	0	0	0		0
2.	Total of O&M Activities	366,596	396,108	364,908	363,896	367,983	369,183	366,596	366,708	365,408	363,896	361,608	361,608	4,414,497	$81,730	$4,332,767
3.	Recoverable Costs Allocated to Energy	358,506	358,518	361,818	360,806	362,318	363,518	363,506	363,618	362,318	360,806	358,518	358,518	4,332,767		
4.	Recoverable Costs Allocated to Demand	8,090	37,590	3,090	3,090	5,665	5,665	3,090	3,090	3,090	3,090	3,090	3,090	81,730		
5.	Retail Energy Jurisdictional Factor	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
6.	Retail Demand Jurisdictional Factor	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
7.	Jurisdictional Energy Recoverable Costs (A)	358,506	358,518	361,818	360,806	362,318	363,518	363,506	363,618	362,318	360,806	358,518	358,518	4,332,767		
8.	Jurisdictional Demand Recoverable Costs (B)	8,090	37,590	3,090	3,090	5,665	5,665	3,090	3,090	3,090	3,090	3,090	3,090	81,730		
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$366,596	$396,108	$364,908	$363,896	$367,983	$369,183	$366,596	$366,708	$365,408	$363,896	$361,608	$361,608	$4,414,497		

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6

Form 42-3P

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line		Description (A)	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	a.	Big Bend Unit 3 Flue Gas Desulfurization Integration	$81,016	$80,783	$80,549	$80,316	$80,083	$79,850	$79,617	$79,383	$79,150	$78,917	$78,683	$78,450	$956,797		$956,797
	b.	Big Bend Units 1 and 2 Flue Gas Conditioning	8,870	8,815	8,759	8,705	8,650	8,594	8,539	8,483	8,428	1,547	0	0	79,390		79,390
	c.	Big Bend Unit 4 Continuous Emissions Monitors	3,492	3,478	3,464	3,451	3,437	3,423	3,409	3,395	3,381	3,367	3,355	3,341	40,993		40,993
	d.	Big Bend Fuel Oil Tank # 1 Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	$0	
	e.	Big Bend Fuel Oil Tank # 2 Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	f.	Big Bend Unit 1 Classifier Replacement	6,898	6,860	6,822	6,784	6,746	6,710	6,672	6,634	6,596	6,559	6,521	6,484	80,286		80,286
	g.	Big Bend Unit 2 Classifier Replacement	4,574	4,551	4,527	4,504	4,481	4,458	4,434	4,411	4,387	4,365	4,341	4,318	53,351		53,351
	h.	Big Bend Section 114 Mercury Testing Platform	682	680	679	676	674	672	670	667	666	664	661	659	8,050		8,050
	i.	Big Bend Units 1 & 2 FGD	156,052	155,379	154,707	154,035	153,362	152,690	152,018	151,345	150,673	150,001	149,329	148,657	1,828,248		1,828,248
	j.	Big Bend FGD Optimization and Utilization	134,545	134,161	133,776	133,392	133,008	132,623	132,239	131,854	131,470	131,086	130,701	130,318	1,589,173		1,589,173
	k.	Big Bend NO_x Emissions Reduction	42,563	42,481	42,399	42,317	42,235	42,153	42,071	41,988	41,906	41,824	41,742	41,660	505,339		505,339
	l.	Big Bend PM Minimization and Monitoring	147,016	146,556	146,096	145,636	145,175	144,715	144,255	143,796	143,336	142,876	142,416	141,956	1,733,829		1,733,829
	m.	Polk NO_x Emissions Reduction	9,358	9,324	9,289	9,254	9,218	9,183	9,148	9,112	9,077	9,042	9,007	8,971	109,983		109,983
	n.	Big Bend Unit 4 SOFA	15,867	15,821	15,774	15,728	15,681	15,635	15,589	15,542	15,496	15,449	15,402	15,357	187,341		187,341
	o.	Big Bend Unit 1 Pre-SCR	11,869	11,822	11,774	11,728	11,681	11,633	11,586	11,540	11,492	11,445	11,397	11,351	139,318		139,318
	p.	Big Bend Unit 2 Pre-SCR	10,619	10,582	10,544	10,507	10,470	10,432	10,395	10,358	10,320	10,282	10,246	10,208	124,963		124,963
	q.	Big Bend Unit 3 Pre-SCR	17,761	17,708	17,656	17,603	17,551	17,498	17,447	17,394	17,342	17,289	17,236	17,185	209,670		209,670
	r.	Big Bend Unit 1 SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	s.	Big Bend Unit 2 SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	t.	Big Bend Unit 3 SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	u.	Big Bend Unit 4 SCR	419,654	418,443	417,233	416,023	414,812	413,602	412,392	411,181	409,971	408,761	407,551	406,340	4,955,963		4,955,963
	v.	Big Bend FGD System Reliability	177,979	177,560	177,142	176,723	176,304	175,885	175,467	175,048	174,630	174,212	173,793	173,375	2,108,118		2,108,118
	w.	Mercury Air Toxics Standards	67,535	67,367	67,201	67,033	66,867	66,699	66,533	66,365	66,199	66,031	65,865	65,697	799,392		799,392
	x.	SO_2 Emissions Allowances (B)	(226)	(226)	(226)	(226)	(226)	(226)	(226)	(226)	(226)	(226)	(226)	(226)	(2,712)		(2,712)
	y.	Big Bend Gypsum Storage Facility	169,633	169,255	168,878	168,500	168,122	167,745	167,367	166,989	166,611	166,233	165,856	165,478	2,010,667		2,010,667
	z.	Big Bend Coal Combustion Residual Rule (CCR Rule)	39,683	42,196	44,702	48,850	54,078	53,948	53,818	53,689	53,559	53,429	53,299	53,169	604,420	604,420	
	aa.	Coal Combustion Residuals (CCR-Phase II)	18,692	18,656	18,619	18,583	18,546	18,510	18,473	18,437	18,400	18,364	18,327	18,292	221,899	221,899	
	ab.	Big Bend ELG Compliance	92,833	103,783	112,920	120,176	128,258	212,190	219,505	232,746	254,191	264,314	267,731	271,238	2,279,885	2,279,885	
	ac.	Big Bend Unit 1 Impingement Mortality - 316(b)	86,494	89,243	91,492	93,896	95,651	96,106	96,132	96,148	96,150	96,150	96,150	96,150	1,129,762	1,129,762	
	ad.	Bayside 316(b) Compliance	1,088	2,377	2,778	4,954	7,130	11,970	16,811	17,211	17,612	24,059	32,110	35,722	173,822	173,822	
2.		Total Investment Projects - Recoverable Costs	1,724,547	1,737,655	1,747,554	1,759,148	1,771,994	1,856,698	1,864,361	1,873,490	1,890,817	1,896,040	1,901,493	1,904,150	21,927,947	$4,409,788	$17,518,159
3.		Recoverable Costs Allocated to Energy	1,485,757	1,481,400	1,477,043	1,472,689	1,468,331	1,463,974	1,459,622	1,455,259	1,450,905	1,439,724	1,433,876	1,429,579	17,518,159		17,518,159
4.		Recoverable Costs Allocated to Demand	238,790	256,255	270,511	286,459	303,663	392,724	404,739	418,231	439,912	456,316	467,617	474,571	4,409,788	4,409,788	
5.		Retail Energy Jurisdictional Factor	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
6.		Retail Demand Jurisdictional Factor	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
7.		Jurisdictional Energy Recoverable Costs (C)	1,485,757	1,481,400	1,477,043	1,472,689	1,468,331	1,463,974	1,459,622	1,455,259	1,450,905	1,439,724	1,433,876	1,429,579	17,518,159		
8.		Jurisdictional Demand Recoverable Costs (D)	238,790	256,255	270,511	286,459	303,663	392,724	404,739	418,231	439,912	456,316	467,617	474,571	4,409,788		
9.		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$1,724,547	$1,737,655	$1,747,554	$1,759,148	$1,771,994	$1,856,698	$1,864,361	$1,873,490	$1,890,817	$1,896,040	$1,901,493	$1,904,150	$21,927,947		

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-4P, Line 9
(B) Project's Total Return Component on Form 42-4P, Line 6
(C) Line 3 x Line 5
(D) Line 4 x Line 6

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Flue Gas Desulfurization Integration
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	
3.	Less: Accumulated Depreciation	(6,824,505)	(6,859,870)	(6,895,235)	(6,930,600)	(6,965,965)	(7,001,330)	(7,036,695)	(7,072,060)	(7,107,425)	(7,142,790)	(7,178,155)	(7,213,520)	(7,248,885)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$6,938,758	6,903,393	6,868,028	6,832,663	6,797,298	6,761,933	6,726,568	6,691,203	6,655,838	6,620,473	6,585,108	6,549,743	6,514,378	
6.	Average Net Investment		6,921,076	6,885,711	6,850,346	6,814,981	6,779,616	6,744,251	6,708,886	6,673,521	6,638,156	6,602,791	6,567,426	6,532,061	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$36,219	$36,034	$35,849	$35,664	$35,479	$35,294	$35,109	$34,924	$34,739	$34,554	$34,368	$34,183	$422,416
	b. Debt Component Grossed Up For Taxes (C)		9,432	9,384	9,335	9,287	9,239	9,191	9,143	9,094	9,046	8,998	8,950	8,902	110,001
8.	Investment Expenses														
	a. Depreciation (D)		35,365	35,365	35,365	35,365	35,365	35,365	35,365	35,365	35,365	35,365	35,365	35,365	424,380
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		81,016	80,783	80,549	80,316	80,083	79,850	79,617	79,383	79,150	78,917	78,683	78,450	956,797
	a. Recoverable Costs Allocated to Energy		81,016	80,783	80,549	80,316	80,083	79,850	79,617	79,383	79,150	78,917	78,683	78,450	956,797
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		81,016	80,783	80,549	80,316	80,083	79,850	79,617	79,383	79,150	78,917	78,683	78,450	956,797
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$81,016	$80,783	$80,549	$80,316	$80,083	$79,850	$79,617	$79,383	$79,150	$78,917	$78,683	$78,450	$956,797

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.45 ($13,435,775), 315.45 ($327,307), and 312.40 ($182).
(B) Line 6 x 6.2798% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 3.1%, 2.4%, and 4.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 Flue Gas Conditioning
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	
3.	Less: Accumulated Depreciation	(4,940,682)	(4,949,072)	(4,957,462)	(4,965,852)	(4,974,242)	(4,982,632)	(4,991,022)	(4,999,412)	(5,007,802)	(5,016,192)	(5,017,734)	(5,017,734)	(5,017,734)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$77,052	68,662	60,272	51,882	43,492	35,102	26,712	18,322	9,932	1,542	0	0	0	
6.	Average Net Investment		72,857	64,467	56,077	47,687	39,297	30,907	22,517	14,127	5,737	771	0	0	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$381	$337	$293	$250	$206	$162	$118	$74	$30	$4	$0	$0	$1,855
	b. Debt Component Grossed Up For Taxes (C)		99	88	76	65	54	42	31	19	8	1	0	0	483
8.	Investment Expenses														
	a. Depreciation (D)		8,390	8,390	8,390	8,390	8,390	8,390	8,390	8,390	8,390	1,542	0	0	77,052
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		8,870	8,815	8,759	8,705	8,650	8,594	8,539	8,483	8,428	1,547	0	0	79,390
	a. Recoverable Costs Allocated to Energy		8,870	8,815	8,759	8,705	8,650	8,594	8,539	8,483	8,428	1,547	0	0	79,390
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		8,870	8,815	8,759	8,705	8,650	8,594	8,539	8,483	8,428	1,547	0	0	79,390
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$8,870	$8,815	$8,759	$8,705	$8,650	$8,594	$8,539	$8,483	$8,428	$1,547	$0	$0	$79,390

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($2,676,217) and 312.42 ($2,341,517).
(B) Line 6 x 6.2798% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 5.2% and 4.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 Continuous Emissions Monitors
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	
3.	Less: Accumulated Depreciation	(653,045)	(655,138)	(657,231)	(659,324)	(661,417)	(663,510)	(665,603)	(667,696)	(669,789)	(671,882)	(673,975)	(676,068)	(678,161)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$213,166	211,073	208,980	206,887	204,794	202,701	200,608	198,515	196,422	194,329	192,236	190,143	188,050	
6.	Average Net Investment		212,120	210,027	207,934	205,841	203,748	201,655	199,562	197,469	195,376	193,283	191,190	189,097	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,110	$1,099	$1,088	$1,077	$1,066	$1,055	$1,044	$1,033	$1,022	$1,011	$1,001	$990	$12,596
	b. Debt Component Grossed Up For Taxes (C)		289	286	283	281	278	275	272	269	266	263	261	258	3,281
8.	Investment Expenses														
	a. Depreciation (D)		2,093	2,093	2,093	2,093	2,093	2,093	2,093	2,093	2,093	2,093	2,093	2,093	25,116
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		3,492	3,478	3,464	3,451	3,437	3,423	3,409	3,395	3,381	3,367	3,355	3,341	40,993
	a. Recoverable Costs Allocated to Energy		3,492	3,478	3,464	3,451	3,437	3,423	3,409	3,395	3,381	3,367	3,355	3,341	40,993
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		3,492	3,478	3,464	3,451	3,437	3,423	3,409	3,395	3,381	3,367	3,355	3,341	40,993
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$3,492	$3,478	$3,464	$3,451	$3,437	$3,423	$3,409	$3,395	$3,381	$3,367	$3,355	$3,341	$40,993

Notes:
(A) Applicable depreciable base for Big Bend; account 315.44
(B) Line 6 x 6.2798% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 2.9%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 1 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	
3.	Less: Accumulated Depreciation	(497,578)	(497,578)	(497,578)	(497,578)	(497,578)	(497,578)	(497,578)	(497,578)	(497,578)	(497,578)	(497,578)	(497,578)	(497,578)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	0	0	0	0	0	0	
6.	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Debt Component Grossed Up For Taxes (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Investment Expenses														
	a. Depreciation (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 6.2798% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 4.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 2 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	
3.	Less: Accumulated Depreciation	(818,401)	(818,401)	(818,401)	(818,401)	(818,401)	(818,401)	(818,401)	(818,401)	(818,401)	(818,401)	(818,401)	(818,401)	(818,401)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	0	0	0	0	0	0	
6.	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Debt Component Grossed Up For Taxes (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Investment Expenses														
	a. Depreciation (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 6.2798% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 4.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	
3.	Less: Accumulated Depreciation	(1,132,472)	(1,138,176)	(1,143,880)	(1,149,584)	(1,155,288)	(1,160,992)	(1,166,696)	(1,172,400)	(1,178,104)	(1,183,808)	(1,189,512)	(1,195,216)	(1,200,920)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$183,785	178,081	172,377	166,673	160,969	155,265	149,561	143,857	138,153	132,449	126,745	121,041	115,337	
6.	Average Net Investment		180,933	175,229	169,525	163,821	158,117	152,413	146,709	141,005	135,301	129,597	123,893	118,189	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$947	$917	$887	$857	$827	$798	$768	$738	$708	$678	$648	$619	$9,392
	b. Debt Component Grossed Up For Taxes (C)		247	239	231	223	215	208	200	192	184	177	169	161	2,446
8.	Investment Expenses														
	a. Depreciation (D)		5,704	5,704	5,704	5,704	5,704	5,704	5,704	5,704	5,704	5,704	5,704	5,704	68,448
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		6,898	6,860	6,822	6,784	6,746	6,710	6,672	6,634	6,596	6,559	6,521	6,484	80,286
	a. Recoverable Costs Allocated to Energy		6,898	6,860	6,822	6,784	6,746	6,710	6,672	6,634	6,596	6,559	6,521	6,484	80,286
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		6,898	6,860	6,822	6,784	6,746	6,710	6,672	6,634	6,596	6,559	6,521	6,484	80,286
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$6,898	$6,860	$6,822	$6,784	$6,746	$6,710	$6,672	$6,634	$6,596	$6,559	$6,521	$6,484	$80,286

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 6.2798% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 5.2%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	
3.	Less: Accumulated Depreciation	(824,598)	(828,127)	(831,656)	(835,185)	(838,714)	(842,243)	(845,772)	(849,301)	(852,830)	(856,359)	(859,888)	(863,417)	(866,946)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$160,196	156,667	153,138	149,609	146,080	142,551	139,022	135,493	131,964	128,435	124,906	121,377	117,848	
6.	Average Net Investment		158,432	154,903	151,374	147,845	144,316	140,787	137,258	133,729	130,200	126,671	123,142	119,613	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$829	$811	$792	$774	$755	$737	$718	$700	$681	$663	$644	$626	$8,730
	b. Debt Component Grossed Up For Taxes (C)		216	211	206	201	197	192	187	182	177	173	168	163	2,273
8.	Investment Expenses														
	a. Depreciation (D)		3,529	3,529	3,529	3,529	3,529	3,529	3,529	3,529	3,529	3,529	3,529	3,529	42,348
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		4,574	4,551	4,527	4,504	4,481	4,458	4,434	4,411	4,387	4,365	4,341	4,318	53,351
	a. Recoverable Costs Allocated to Energy		4,574	4,551	4,527	4,504	4,481	4,458	4,434	4,411	4,387	4,365	4,341	4,318	53,351
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		4,574	4,551	4,527	4,504	4,481	4,458	4,434	4,411	4,387	4,365	4,341	4,318	53,351
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
15	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$4,574	$4,551	$4,527	$4,504	$4,481	$4,458	$4,434	$4,411	$4,387	$4,365	$4,341	$4,318	$53,351

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 6.2798% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 4.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Section 114 Mercury Testing Platform
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	
3.	Less: Accumulated Depreciation	(65,923)	(66,245)	(66,567)	(66,889)	(67,211)	(67,533)	(67,855)	(68,177)	(68,499)	(68,821)	(69,143)	(69,465)	(69,787)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$54,814	54,492	54,170	53,848	53,526	53,204	52,882	52,560	52,238	51,916	51,594	51,272	50,950	
6.	Average Net Investment		54,653	54,331	54,009	53,687	53,365	53,043	52,721	52,399	52,077	51,755	51,433	51,111	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$286	$284	$283	$281	$279	$278	$276	$274	$273	$271	$269	$267	$3,321
	b. Debt Component Grossed Up For Taxes (C)		74	74	74	73	73	72	72	71	71	71	70	70	865
8.	Investment Expenses														
	a. Depreciation (D)		322	322	322	322	322	322	322	322	322	322	322	322	3,864
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		682	680	679	676	674	672	670	667	666	664	661	659	8,050
	a. Recoverable Costs Allocated to Energy		682	680	679	676	674	672	670	667	666	664	661	659	8,050
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		682	680	679	676	674	672	670	667	666	664	661	659	8,050
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$682	$680	$679	$676	$674	$672	$670	$667	$666	$664	$661	$659	$8,050

Notes:
(A) Applicable depreciable base for Big Bend; account 311.40
(B) Line 6 x 6.2798% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 3.2%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 FGD
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$28,490,542	$28,490,542	$28,490,542	$28,490,542	$28,490,542	$28,490,542	$28,490,542	$28,490,542	$28,490,542	$28,490,542	$28,490,542	$28,490,542	$28,490,542	
3.	Less: Accumulated Depreciation	(20,232,926)	(20,334,847)	(20,436,768)	(20,538,689)	(20,640,610)	(20,742,531)	(20,844,452)	(20,946,373)	(21,048,294)	(21,150,215)	(21,252,136)	(21,354,057)	(21,455,978)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$8,257,617	8,155,696	8,053,775	7,951,854	7,849,933	7,748,012	7,646,091	7,544,170	7,442,249	7,340,328	7,238,407	7,136,486	7,034,565	
6.	Average Net Investment		8,206,656	8,104,735	8,002,814	7,900,893	7,798,972	7,697,051	7,595,130	7,493,209	7,391,288	7,289,367	7,187,446	7,085,525	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$42,947	$42,413	$41,880	$41,347	$40,813	$40,280	$39,747	$39,213	$38,680	$38,146	$37,613	$37,080	$480,159
	b. Debt Component Grossed Up For Taxes (C)		11,184	11,045	10,906	10,767	10,628	10,489	10,350	10,211	10,072	9,934	9,795	9,656	125,037
8.	Investment Expenses														
	a. Depreciation (D)		101,921	101,921	101,921	101,921	101,921	101,921	101,921	101,921	101,921	101,921	101,921	101,921	1,223,052
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		156,052	155,379	154,707	154,035	153,362	152,690	152,018	151,345	150,673	150,001	149,329	148,657	1,828,248
	a. Recoverable Costs Allocated to Energy		156,052	155,379	154,707	154,035	153,362	152,690	152,018	151,345	150,673	150,001	149,329	148,657	1,828,248
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		156,052	155,379	154,707	154,035	153,362	152,690	152,018	151,345	150,673	150,001	149,329	148,657	1,828,248
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$156,052	$155,379	$154,707	$154,035	$153,362	$152,690	$152,018	$151,345	$150,673	$150,001	$149,329	$148,657	$1,828,248

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.46 ($141,968), 312.46 ($28,341,531), and 315.46 ($7,043).
(B) Line 6 x 6.2798% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 2.9%, 4.3%, and 3.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD Optimization and Utilization
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	
3.	Less: Accumulated Depreciation	(11,060,534)	(11,118,802)	(11,177,070)	(11,235,338)	(11,293,606)	(11,351,874)	(11,410,142)	(11,468,410)	(11,526,678)	(11,584,946)	(11,643,214)	(11,701,482)	(11,759,750)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$11,593,395	11,535,127	11,476,859	11,418,591	11,360,323	11,302,055	11,243,787	11,185,519	11,127,251	11,068,983	11,010,715	10,952,447	10,894,179	
6.	Average Net Investment		11,564,261	11,505,993	11,447,725	11,389,457	11,331,189	11,272,921	11,214,653	11,156,385	11,098,117	11,039,849	10,981,581	10,923,313	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$60,518	$60,213	$59,908	$59,603	$59,298	$58,993	$58,688	$58,383	$58,078	$57,773	$57,468	$57,164	$706,087
	b. Debt Component Grossed Up For Taxes (C)		15,759	15,680	15,600	15,521	15,442	15,362	15,283	15,203	15,124	15,045	14,965	14,886	183,870
8.	Investment Expenses														
	a. Depreciation (D)		58,268	58,268	58,268	58,268	58,268	58,268	58,268	58,268	58,268	58,268	58,268	58,268	699,216
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		134,545	134,161	133,776	133,392	133,008	132,623	132,239	131,854	131,470	131,086	130,701	130,318	1,589,173
	a. Recoverable Costs Allocated to Energy		134,545	134,161	133,776	133,392	133,008	132,623	132,239	131,854	131,470	131,086	130,701	130,318	1,589,173
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		134,545	134,161	133,776	133,392	133,008	132,623	132,239	131,854	131,470	131,086	130,701	130,318	1,589,173
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$134,545	$134,161	$133,776	$133,392	$133,008	$132,623	$132,239	$131,854	$131,470	$131,086	$130,701	$130,318	$1,589,173

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.45 ($21,855,886), 311.45 ($40,016), 316.40 ($71,401), 315.45 ($594,901), 312.42 ($1,637), and 312.40 ($90,088).
(B) Line 6 x 6.2798% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 3.1%, 2.1%, 3.3%, 2.4%, 4.3%, and 4.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	
3.	Less: Accumulated Depreciation	1,383,147	1,370,713	1,358,279	1,345,845	1,333,411	1,320,977	1,308,543	1,296,109	1,283,675	1,271,241	1,258,807	1,246,373	1,233,939	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$4,573,999	4,561,565	4,549,131	4,536,697	4,524,263	4,511,829	4,499,395	4,486,961	4,474,527	4,462,093	4,449,659	4,437,225	4,424,791	
6.	Average Net Investment		4,567,782	4,555,348	4,542,914	4,530,480	4,518,046	4,505,612	4,493,178	4,480,744	4,468,310	4,455,876	4,443,442	4,431,008	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$23,904	$23,839	$23,774	$23,709	$23,644	$23,579	$23,514	$23,448	$23,383	$23,318	$23,253	$23,188	$282,553
	b. Debt Component Grossed Up For Taxes (C)		6,225	6,208	6,191	6,174	6,157	6,140	6,123	6,106	6,089	6,072	6,055	6,038	73,578
8.	Investment Expenses														
	a. Depreciation (D)		12,434	12,434	12,434	12,434	12,434	12,434	12,434	12,434	12,434	12,434	12,434	12,434	149,208
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		42,563	42,481	42,399	42,317	42,235	42,153	42,071	41,988	41,906	41,824	41,742	41,660	505,339
	a. Recoverable Costs Allocated to Energy		42,563	42,481	42,399	42,317	42,235	42,153	42,071	41,988	41,906	41,824	41,742	41,660	505,339
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		42,563	42,481	42,399	42,317	42,235	42,153	42,071	41,988	41,906	41,824	41,742	41,660	505,339
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$42,563	$42,481	$42,399	$42,317	$42,235	$42,153	$42,071	$41,988	$41,906	$41,824	$41,742	$41,660	$505,339

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,675,171), 312.42 ($1,075,718), and 312.43 ($439,963).
(B) Line 6 x 6.2798% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 5.2%, 4.3%, and 3.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: PM Minimization and Monitoring
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	
3.	Less: Accumulated Depreciation	(8,005,714)	(8,075,444)	(8,145,174)	(8,214,904)	(8,284,634)	(8,354,364)	(8,424,094)	(8,493,824)	(8,563,554)	(8,633,284)	(8,703,014)	(8,772,744)	(8,842,474)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$11,752,036	11,682,306	11,612,576	11,542,846	11,473,116	11,403,386	11,333,656	11,263,926	11,194,196	11,124,466	11,054,736	10,985,006	10,915,276	
6.	Average Net Investment		11,717,171	11,647,441	11,577,711	11,507,981	11,438,251	11,368,521	11,298,791	11,229,061	11,159,331	11,089,601	11,019,871	10,950,141	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$61,318	$60,953	$60,588	$60,223	$59,858	$59,493	$59,128	$58,764	$58,399	$58,034	$57,669	$57,304	$711,731
	b. Debt Component Grossed Up For Taxes (C)		15,968	15,873	15,778	15,683	15,587	15,492	15,397	15,302	15,207	15,112	15,017	14,922	185,338
8.	Investment Expenses														
	a. Depreciation (D)		69,730	69,730	69,730	69,730	69,730	69,730	69,730	69,730	69,730	69,730	69,730	69,730	836,760
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		147,016	146,556	146,096	145,636	145,175	144,715	144,255	143,796	143,336	142,876	142,416	141,956	1,733,829
	a. Recoverable Costs Allocated to Energy		147,016	146,556	146,096	145,636	145,175	144,715	144,255	143,796	143,336	142,876	142,416	141,956	1,733,829
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		147,016	146,556	146,096	145,636	145,175	144,715	144,255	143,796	143,336	142,876	142,416	141,956	1,733,829
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$147,016	$146,556	$146,096	$145,636	$145,175	$144,715	$144,255	$143,796	$143,336	$142,876	$142,416	$141,956	$1,733,829

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($5,831,465), 312.42 ($5,153,072), 312.43 ($7,875,560), 315.41 ($17,504), 315.44 ($351,594), and 315.43 ($528,554).
(B) Line 6 x 6.2798% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 5.2%, 4.3%, 3.6%, 4.4%, 2.9%, and 3.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Polk NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	
3.	Less: Accumulated Depreciation	(948,762)	(954,097)	(959,432)	(964,767)	(970,102)	(975,437)	(980,772)	(986,107)	(991,442)	(996,777)	(1,002,112)	(1,007,447)	(1,012,782)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$612,711	607,376	602,041	596,706	591,371	586,036	580,701	575,366	570,031	564,696	559,361	554,026	548,691	
6.	Average Net Investment		610,044	604,709	599,374	594,039	588,704	583,369	578,034	572,699	567,364	562,029	556,694	551,359	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$3,192	$3,165	$3,137	$3,109	$3,081	$3,053	$3,025	$2,997	$2,969	$2,941	$2,913	$2,885	$36,467
	b. Debt Component Grossed Up For Taxes (C)		831	824	817	810	802	795	788	780	773	766	759	751	9,496
8.	Investment Expenses														
	a. Depreciation (D)		5,335	5,335	5,335	5,335	5,335	5,335	5,335	5,335	5,335	5,335	5,335	5,335	64,020
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		9,358	9,324	9,289	9,254	9,218	9,183	9,148	9,112	9,077	9,042	9,007	8,971	109,983
	a. Recoverable Costs Allocated to Energy		9,358	9,324	9,289	9,254	9,218	9,183	9,148	9,112	9,077	9,042	9,007	8,971	109,983
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		9,358	9,324	9,289	9,254	9,218	9,183	9,148	9,112	9,077	9,042	9,007	8,971	109,983
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$9,358	$9,324	$9,289	$9,254	$9,218	$9,183	$9,148	$9,112	$9,077	$9,042	$9,007	$8,971	$109,983

Notes:
(A) Applicable depreciable base for Polk; account 342.81
(B) Line 6 x 6.2798% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 4.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SOFA
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	
3.	Less: Accumulated Depreciation	(1,216,490)	(1,223,527)	(1,230,564)	(1,237,601)	(1,244,638)	(1,251,675)	(1,258,712)	(1,265,749)	(1,272,786)	(1,279,823)	(1,286,860)	(1,293,897)	(1,300,934)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,342,240	1,335,203	1,328,166	1,321,129	1,314,092	1,307,055	1,300,018	1,292,981	1,285,944	1,278,907	1,271,870	1,264,833	1,257,796	
6.	Average Net Investment		1,338,722	1,331,685	1,324,648	1,317,611	1,310,574	1,303,537	1,296,500	1,289,463	1,282,426	1,275,389	1,268,352	1,261,315	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$7,006	$6,969	$6,932	$6,895	$6,858	$6,822	$6,785	$6,748	$6,711	$6,674	$6,637	$6,601	$81,638
	b. Debt Component Grossed Up For Taxes (C)		1,824	1,815	1,805	1,796	1,786	1,776	1,767	1,757	1,748	1,738	1,728	1,719	21,259
8.	Investment Expenses														
	a. Depreciation (D)		7,037	7,037	7,037	7,037	7,037	7,037	7,037	7,037	7,037	7,037	7,037	7,037	84,444
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		15,867	15,821	15,774	15,728	15,681	15,635	15,589	15,542	15,496	15,449	15,402	15,357	187,341
	a. Recoverable Costs Allocated to Energy		15,867	15,821	15,774	15,728	15,681	15,635	15,589	15,542	15,496	15,449	15,402	15,357	187,341
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		15,867	15,821	15,774	15,728	15,681	15,635	15,589	15,542	15,496	15,449	15,402	15,357	187,341
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$15,867	$15,821	$15,774	$15,728	$15,681	$15,635	$15,589	$15,542	$15,496	$15,449	$15,402	$15,357	$187,341

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44
(B) Line 6 x 6.2798% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 3.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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FILED: 10/01/2021

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	
3.	Less: Accumulated Depreciation	(929,485)	(936,631)	(943,777)	(950,923)	(958,069)	(965,215)	(972,361)	(979,507)	(986,653)	(993,799)	(1,000,945)	(1,008,091)	(1,015,237)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$719,636	712,490	705,344	698,198	691,052	683,906	676,760	669,614	662,468	655,322	648,176	641,030	633,884	
6.	Average Net Investment		716,063	708,917	701,771	694,625	687,479	680,333	673,187	666,041	658,895	651,749	644,603	637,457	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$3,747	$3,710	$3,672	$3,635	$3,598	$3,560	$3,523	$3,486	$3,448	$3,411	$3,373	$3,336	$42,499
	b. Debt Component Grossed Up For Taxes (C)		976	966	956	947	937	927	917	908	898	888	878	869	11,067
8.	Investment Expenses														
	a. Depreciation (D)		7,146	7,146	7,146	7,146	7,146	7,146	7,146	7,146	7,146	7,146	7,146	7,146	85,752
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		11,869	11,822	11,774	11,728	11,681	11,633	11,586	11,540	11,492	11,445	11,397	11,351	139,318
	a. Recoverable Costs Allocated to Energy		11,869	11,822	11,774	11,728	11,681	11,633	11,586	11,540	11,492	11,445	11,397	11,351	139,318
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		11,869	11,822	11,774	11,728	11,681	11,633	11,586	11,540	11,492	11,445	11,397	11,351	139,318
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$11,869	$11,822	$11,774	$11,728	$11,681	$11,633	$11,586	$11,540	$11,492	$11,445	$11,397	$11,351	$139,318

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 6.2798% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 5.2%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	
3.	Less: Accumulated Depreciation	(828,416)	(834,084)	(839,752)	(845,420)	(851,088)	(856,756)	(862,424)	(868,092)	(873,760)	(879,428)	(885,096)	(890,764)	(896,432)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$753,471	747,803	742,135	736,467	730,799	725,131	719,463	713,795	708,127	702,459	696,791	691,123	685,455	
6.	Average Net Investment		750,637	744,969	739,301	733,633	727,965	722,297	716,629	710,961	705,293	699,625	693,957	688,289	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$3,928	$3,899	$3,869	$3,839	$3,810	$3,780	$3,750	$3,721	$3,691	$3,661	$3,632	$3,602	$45,182
	b. Debt Component Grossed Up For Taxes (C)		1,023	1,015	1,007	1,000	992	984	977	969	961	953	946	938	11,765
8.	Investment Expenses														
	a. Depreciation (D)		5,668	5,668	5,668	5,668	5,668	5,668	5,668	5,668	5,668	5,668	5,668	5,668	68,016
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		10,619	10,582	10,544	10,507	10,470	10,432	10,395	10,358	10,320	10,282	10,246	10,208	124,963
	a. Recoverable Costs Allocated to Energy		10,619	10,582	10,544	10,507	10,470	10,432	10,395	10,358	10,320	10,282	10,246	10,208	124,963
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		10,619	10,582	10,544	10,507	10,470	10,432	10,395	10,358	10,320	10,282	10,246	10,208	124,963
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$10,619	$10,582	$10,544	$10,507	$10,470	$10,432	$10,395	$10,358	$10,320	$10,282	$10,246	$10,208	$124,963

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 6.2798% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 4.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	
3.	Less: Accumulated Depreciation	(1,213,946)	(1,221,888)	(1,229,830)	(1,237,772)	(1,245,714)	(1,253,656)	(1,261,598)	(1,269,540)	(1,277,482)	(1,285,424)	(1,293,366)	(1,301,308)	(1,309,250)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,492,561	1,484,619	1,476,677	1,468,735	1,460,793	1,452,851	1,444,909	1,436,967	1,429,025	1,421,083	1,413,141	1,405,199	1,397,257	
6.	Average Net Investment		1,488,590	1,480,648	1,472,706	1,464,764	1,456,822	1,448,880	1,440,938	1,432,996	1,425,054	1,417,112	1,409,170	1,401,228	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$7,790	$7,748	$7,707	$7,665	$7,624	$7,582	$7,541	$7,499	$7,458	$7,416	$7,374	$7,333	$90,737
	b. Debt Component Grossed Up For Taxes (C)		2,029	2,018	2,007	1,996	1,985	1,974	1,964	1,953	1,942	1,931	1,920	1,910	23,629
8.	Investment Expenses														
	a. Depreciation (D)		7,942	7,942	7,942	7,942	7,942	7,942	7,942	7,942	7,942	7,942	7,942	7,942	95,304
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		17,761	17,708	17,656	17,603	17,551	17,498	17,447	17,394	17,342	17,289	17,236	17,185	209,670
	a. Recoverable Costs Allocated to Energy		17,761	17,708	17,656	17,603	17,551	17,498	17,447	17,394	17,342	17,289	17,236	17,185	209,670
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		17,761	17,708	17,656	17,603	17,551	17,498	17,447	17,394	17,342	17,289	17,236	17,185	209,670
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$17,761	$17,708	$17,656	$17,603	$17,551	$17,498	$17,447	$17,394	$17,342	$17,289	$17,236	$17,185	$209,670

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.43 ($1,995,677) and 315.43 ($710,830).
(B) Line 6 x 6.2798% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 3.6% and 3.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	0	0	0	0	0	0	
6.	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Debt Component Grossed Up For Taxes (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Investment Expenses														
	a. Depreciation (D)		-	-	-	-	-	-	-	-	-	-	-	-	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:
(A) Applicable depreciable base for Big Bend; account 311.51 ($0), 312.51 ($0), 315.51 ($0), and 316.51 ($0).
(B) Line 6 x 6.2798% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12.
(D) Applicable depreciation rate is 4.0%, 4.3%, 4.0% and 4.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	0	0	0	0	0	0	
6.	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Debt Component Grossed Up For Taxes (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Investment Expenses														
	a. Depreciation (D)		-	-	-	-	-	-	-	-	-	-	-	-	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:
(A) Applicable depreciable base for Big Bend; account 311.52 ($0), 312.52 ($0), 315.52 ($0), and 316.52 ($0).
(B) Line 6 x 6.2798% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12.
(D) Applicable depreciation rates are 3.5%, 4.0%, 3.7% and 3.4%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	0	0	0	0	0	0	
6.	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Debt Component Grossed Up For Taxes (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Investment Expenses														
	a. Depreciation (D)		-	-	-	-	-	-	-	-	-	-	-	-	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:
(A) Applicable depreciable base for Big Bend; account 311.53 ($0), 312.53 ($0), 315.53 ($0), and 316.53 ($0).
(B) Line 6 x 6.2798% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12.
(D) Applicable depreciation rates are 3.1%, 3.5%, 3.2%, and 2.9%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$67,588,833	$67,588,833	$67,588,833	$67,588,833	$67,588,833	$67,588,833	$67,588,833	$67,588,833	$67,588,833	$67,588,833	$67,588,833	$67,588,833	$67,588,833	
3.	Less: Accumulated Depreciation	(31,694,919)	(31,878,425)	(32,061,931)	(32,245,437)	(32,428,943)	(32,612,449)	(32,795,955)	(32,979,461)	(33,162,967)	(33,346,473)	(33,529,979)	(33,713,485)	(33,896,991)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$35,893,914	35,710,408	35,526,902	35,343,396	35,159,890	34,976,384	34,792,878	34,609,372	34,425,866	34,242,360	34,058,854	33,875,348	33,691,842	
6.	Average Net Investment		35,802,161	35,618,655	35,435,149	35,251,643	35,068,137	34,884,631	34,701,125	34,517,619	34,334,113	34,150,607	33,967,101	33,783,595	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$187,359	$186,398	$185,438	$184,478	$183,517	$182,557	$181,597	$180,636	$179,676	$178,716	$177,756	$176,795	$2,184,923
	b. Debt Component Grossed Up For Taxes (C)		48,789	48,539	48,289	48,039	47,789	47,539	47,289	47,039	46,789	46,539	46,289	46,039	568,968
8.	Investment Expenses														
	a. Depreciation (D)		183,506	183,506	183,506	183,506	183,506	183,506	183,506	183,506	183,506	183,506	183,506	183,506	2,202,072
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		419,654	418,443	417,233	416,023	414,812	413,602	412,392	411,181	409,971	408,761	407,551	406,340	4,955,963
	a. Recoverable Costs Allocated to Energy		419,654	418,443	417,233	416,023	414,812	413,602	412,392	411,181	409,971	408,761	407,551	406,340	4,955,963
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		419,654	418,443	417,233	416,023	414,812	413,602	412,392	411,181	409,971	408,761	407,551	406,340	4,955,963
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$419,654	$418,443	$417,233	$416,023	$414,812	$413,602	$412,392	$411,181	$409,971	$408,761	$407,551	$406,340	$4,955,963

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.54 ($16,857,250), 312.54 ($38,069,546), 315.54 ($10,642,027), 316.54 ($687,934), 315.40 ($558,103), and 312.44 ($773,972).
(B) Line 6 x 6.2798% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 2.8%, 3.6%, 2.8%, 2.4%, 3.5%, and 3.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD System Reliability
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	
3.	Less: Accumulated Depreciation	(7,072,849)	(7,136,301)	(7,199,753)	(7,263,205)	(7,326,657)	(7,390,109)	(7,453,561)	(7,517,013)	(7,580,465)	(7,643,917)	(7,707,369)	(7,770,821)	(7,834,273)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$17,394,957	17,331,505	17,268,053	17,204,601	17,141,149	17,077,697	17,014,245	16,950,793	16,887,341	16,823,889	16,760,437	16,696,985	16,633,533	
6.	Average Net Investment		17,363,231	17,299,779	17,236,327	17,172,875	17,109,423	17,045,971	16,982,519	16,919,067	16,855,615	16,792,163	16,728,711	16,665,259	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$90,865	$90,533	$90,201	$89,869	$89,536	$89,204	$88,872	$88,540	$88,208	$87,876	$87,544	$87,212	$1,068,460
	b. Debt Component Grossed Up For Taxes (C)		23,662	23,575	23,489	23,402	23,316	23,229	23,143	23,056	22,970	22,884	22,797	22,711	278,234
8.	Investment Expenses														
	a. Depreciation (D)		63,452	63,452	63,452	63,452	63,452	63,452	63,452	63,452	63,452	63,452	63,452	63,452	761,424
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		177,979	177,560	177,142	176,723	176,304	175,885	175,467	175,048	174,630	174,212	173,793	173,375	2,108,118
	a. Recoverable Costs Allocated to Energy		177,979	177,560	177,142	176,723	176,304	175,885	175,467	175,048	174,630	174,212	173,793	173,375	2,108,118
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		177,979	177,560	177,142	176,723	176,304	175,885	175,467	175,048	174,630	174,212	173,793	173,375	2,108,118
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$177,979	$177,560	$177,142	$176,723	$176,304	$175,885	$175,467	$175,048	$174,630	$174,212	$173,793	$173,375	$2,108,118

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.45 ($23,011,597) and 312.44 ($1,456,209).
(B) Line 6 x 6.2798% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 3.1% and 3.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Mercury Air Toxics Standards (MATS)
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$8,635,028	$8,635,028	$8,635,028	$8,635,028	$8,635,028	$8,635,028	$8,635,028	$8,635,028	$8,635,028	$8,635,028	$8,635,028	$8,635,028	$8,635,028	
3.	Less: Accumulated Depreciation	(2,223,006)	(2,248,331)	(2,273,656)	(2,298,981)	(2,324,306)	(2,349,631)	(2,374,956)	(2,400,281)	(2,425,606)	(2,450,931)	(2,476,256)	(2,501,581)	(2,526,906)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$6,412,022	6,386,697	6,361,372	6,336,047	6,310,722	6,285,397	6,260,072	6,234,747	6,209,422	6,184,097	6,158,772	6,133,447	6,108,122	
6.	Average Net Investment		6,399,359	6,374,034	6,348,709	6,323,384	6,298,059	6,272,734	6,247,409	6,222,084	6,196,759	6,171,434	6,146,109	6,120,784	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$33,489	$33,356	$33,224	$33,091	$32,959	$32,826	$32,694	$32,561	$32,429	$32,296	$32,164	$32,031	$393,120
	b. Debt Component Grossed Up For Taxes (C)		8,721	8,686	8,652	8,617	8,583	8,548	8,514	8,479	8,445	8,410	8,376	8,341	102,372
8.	Investment Expenses														
	a. Depreciation (D)		25,325	25,325	25,325	25,325	25,325	25,325	25,325	25,325	25,325	25,325	25,325	25,325	303,900
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		67,535	67,367	67,201	67,033	66,867	66,699	66,533	66,365	66,199	66,031	65,865	65,697	799,392
	a. Recoverable Costs Allocated to Energy		67,535	67,367	67,201	67,033	66,867	66,699	66,533	66,365	66,199	66,031	65,865	65,697	799,392
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		67,535	67,367	67,201	67,033	66,867	66,699	66,533	66,365	66,199	66,031	65,865	65,697	799,392
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$67,535	$67,367	$67,201	$67,033	$66,867	$66,699	$66,533	$66,365	$66,199	$66,031	$65,865	$65,697	$799,392

Notes:

(A) Applicable depreciable base for Big Bend and Polk; accounts 312.44 ($3,427,481), 341.80 ($26,150), 315.40 ($1,226,949), 315.41 ($138,853), 315.42 ($138,853), 312.45 ($2,053,017), 312.46 ($1,242,315), 315.44 ($16,035), 315.45 ($40,217), 315.46 ($50,784), 311.40 ($13,216), 345.81 ($2,232), 312.54 ($210,295), 312.40 ($13,614), and 395.00 ($35,018).
(B) Line 6 x 6.2798% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 3.3%, 3.1%, 3.5%, 4.4%, 5.0%, 3.1%, 4.3%, 2.9%, 2.4%, 3.5%, 3.2%, 3.3%, 3.6%, 4.6%, and 14.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

For Project: SO_2 Emissions Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Purchases/Transfers		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Working Capital Balance														0
	a. FERC 158.1 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
	b. FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c. FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d. FERC 254.01 Regulatory Liabilities - Gains	(34,201)	(34,189)	(34,189)	(34,189)	(34,177)	(34,177)	(34,177)	(34,164)	(34,164)	(34,164)	(34,152)	(34,152)	(34,152)	
3.	Total Working Capital Balance	($34,201)	(34,189)	(34,189)	(34,189)	(34,177)	(34,177)	(34,177)	(34,164)	(34,164)	(34,164)	(34,152)	(34,152)	(34,152)	
4.	Average Net Working Capital Balance		($34,195)	($34,189)	($34,189)	($34,183)	($34,177)	($34,177)	($34,171)	($34,164)	($34,164)	($34,158)	($34,152)	($34,152)	
5.	Return on Average Net Working Capital Balance														
	a. Equity Component Grossed Up For Taxes (A)		($179)	($179)	($179)	($179)	($179)	($179)	($179)	($179)	($179)	($179)	($179)	($179)	(2,148)
	b. Debt Component Grossed Up For Taxes (B)		(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(564)
6.	Total Return Component		(226)	(226)	(226)	(226)	(226)	(226)	(226)	(226)	(226)	(226)	(226)	(226)	(2,712)
7.	Expenses:														
	a. Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. SO_2 Allowance Expense		(5)	7	7	(5)	7	7	(5)	7	7	(5)	7	7	41
8.	Net Expenses (D)		(5)	7	7	(5)	7	7	(5)	7	7	(5)	7	7	41
9.	Total System Recoverable Expenses (Lines 6 + 8)		(231)	(219)	(219)	(231)	(219)	(219)	(231)	(219)	(219)	(231)	(219)	(219)	(2,671)
	a. Recoverable Costs Allocated to Energy		(231)	(219)	(219)	(231)	(219)	(219)	(231)	(219)	(219)	(231)	(219)	(219)	(2,671)
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		(231)	(219)	(219)	(231)	(219)	(219)	(231)	(219)	(219)	(231)	(219)	(219)	(2,676)
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Juris. Recoverable Costs (Lines 12 + 13)		($231)	($219)	($219)	($231)	($219)	($219)	($231)	($219)	($219)	($231)	($219)	($219)	($2,676)

Notes:
(A) Line 6 x 6.2798% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(B) Line 6 x 1.6353% x 1/12
(C) Line 6 is reported on Schedule 7E.
(D) Line 8 is reported on Schedule 5E.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Gypsum Storage Facility
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	
3.	Less: Accumulated Depreciation	(4,399,971)	(4,457,217)	(4,514,463)	(4,571,709)	(4,628,955)	(4,686,201)	(4,743,447)	(4,800,693)	(4,857,939)	(4,915,185)	(4,972,431)	(5,029,677)	(5,086,923)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$17,067,388	17,010,142	16,952,896	16,895,650	16,838,404	16,781,158	16,723,912	16,666,666	16,609,420	16,552,174	16,494,928	16,437,682	16,380,436	
6.	Average Net Investment		17,038,765	16,981,519	16,924,273	16,867,027	16,809,781	16,752,535	16,695,289	16,638,043	16,580,797	16,523,551	16,466,305	16,409,059	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$89,167	$88,867	$88,568	$88,268	$87,968	$87,669	$87,369	$87,070	$86,770	$86,470	$86,171	$85,871	$1,050,228
	b. Debt Component Grossed Up For Taxes (C)		23,220	23,142	23,064	22,986	22,908	22,830	22,752	22,673	22,595	22,517	22,439	22,361	273,487
8.	Investment Expenses														
	a. Depreciation (D)		57,246	57,246	57,246	57,246	57,246	57,246	57,246	57,246	57,246	57,246	57,246	57,246	686,952
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		169,633	169,255	168,878	168,500	168,122	167,745	167,367	166,989	166,611	166,233	165,856	165,478	2,010,667
	a. Recoverable Costs Allocated to Energy		169,633	169,255	168,878	168,500	168,122	167,745	167,367	166,989	166,611	166,233	165,856	165,478	2,010,667
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		169,633	169,255	168,878	168,500	168,122	167,745	167,367	166,989	166,611	166,233	165,856	165,478	2,010,667
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$169,633	$169,255	$168,878	$168,500	$168,122	$167,745	$167,367	$166,989	$166,611	$166,233	$165,856	$165,478	$2,010,667

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.40
(B) Line 6 x 6.2798% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 3.2%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Coal Combustion Residual Rule (CCR Rule)
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$250,000	$250,000	$250,000	$750,000	$0	$0	$0	$0	$0	$0	$0	$0	$1,500,000
	b. Clearings to Plant		250,000	250,000	250,000	750,000	0	0	0	0	0	0	0	0	1,500,000
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$3,903,531	$4,153,531	$4,403,531	$4,653,531	$5,403,531	$5,403,531	$5,403,531	$5,403,531	$5,403,531	$5,403,531	$5,403,531	$5,403,531	$5,403,531	
3.	Less: Accumulated Depreciation	(117,761)	(131,695)	(146,588)	(162,439)	(179,248)	(198,932)	(218,616)	(238,300)	(257,984)	(277,668)	(297,352)	(317,036)	(336,720)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$3,785,770	4,021,836	4,256,943	4,491,092	5,224,283	5,204,599	5,184,915	5,165,231	5,145,547	5,125,863	5,106,179	5,086,495	5,066,811	
6.	Average Net Investment		3,903,803	4,139,390	4,374,018	4,857,688	5,214,441	5,194,757	5,175,073	5,155,389	5,135,705	5,116,021	5,096,337	5,076,653	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$20,429	$21,662	$22,890	$25,421	$27,288	$27,185	$27,082	$26,979	$26,876	$26,773	$26,670	$26,567	$305,822
	b. Debt Component Grossed Up For Taxes (C)		5,320	5,641	5,961	6,620	7,106	7,079	7,052	7,026	6,999	6,972	6,945	6,918	79,639
8.	Investment Expenses														
	a. Depreciation (D)		13,934	14,893	15,851	16,809	19,684	19,684	19,684	19,684	19,684	19,684	19,684	19,684	218,959
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		39,683	42,196	44,702	48,850	54,078	53,948	53,818	53,689	53,559	53,429	53,299	53,169	604,420
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		39,683	42,196	44,702	48,850	54,078	53,948	53,818	53,689	53,559	53,429	53,299	53,169	604,420
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		39,683	42,196	44,702	48,850	54,078	53,948	53,818	53,689	53,559	53,429	53,299	53,169	604,420
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$39,683	$42,196	$44,702	$48,850	$54,078	$53,948	$53,818	$53,689	$53,559	$53,429	$53,299	$53,169	$604,420

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.40 ($261,568), 312.44 ($668,735) and 312.40 ($4,473,228).
(B) Line 6 x 6.2798% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 3.2%, 3.3% and 4.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Coal Combustion Residuals (CCR Rule - Phase II)
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$2,009,031	$2,009,031	$2,009,031	$2,009,031	$2,009,031	$2,009,031	$2,009,031	$2,009,031	$2,009,031	$2,009,031	$2,009,031	$2,009,031	$2,009,031	
3.	Less: Accumulated Depreciation	(10,046)	(15,571)	(21,096)	(26,621)	(32,146)	(37,671)	(43,196)	(48,721)	(54,246)	(59,771)	(65,296)	(70,821)	(76,346)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,998,985	1,993,460	1,987,935	1,982,410	1,976,885	1,971,360	1,965,835	1,960,310	1,954,785	1,949,260	1,943,735	1,938,210	1,932,685	
6.	Average Net Investment		1,996,223	1,990,698	1,985,173	1,979,648	1,974,123	1,968,598	1,963,073	1,957,548	1,952,023	1,946,498	1,940,973	1,935,448	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$10,447	$10,418	$10,389	$10,360	$10,331	$10,302	$10,273	$10,244	$10,215	$10,186	$10,157	$10,129	$123,451
	b. Debt Component Grossed Up For Taxes (C)		2,720	2,713	2,705	2,698	2,690	2,683	2,675	2,668	2,660	2,653	2,645	2,638	32,148
8.	Investment Expenses														
	a. Depreciation (D)		5,525	5,525	5,525	5,525	5,525	5,525	5,525	5,525	5,525	5,525	5,525	5,525	66,300
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		18,692	18,656	18,619	18,583	18,546	18,510	18,473	18,437	18,400	18,364	18,327	18,292	221,899
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		18,692	18,656	18,619	18,583	18,546	18,510	18,473	18,437	18,400	18,364	18,327	18,292	221,899
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		18,692	18,656	18,619	18,583	18,546	18,510	18,473	18,437	18,400	18,364	18,327	18,292	221,899
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$18,692	$18,656	$18,619	$18,583	$18,546	$18,510	$18,473	$18,437	$18,400	$18,364	$18,327	$18,292	$221,899

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.44
(B) Line 6 x 6.2798% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 3.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend ELG Compliance
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$1,685,199	$1,635,199	$1,135,199	$1,065,199	$1,385,199	$735,199	$785,199	$2,480,199	$1,315,199	$415,199	$335,199	$538,245	$13,510,436
	b. Clearings to Plant		0	0	0	0	20,137,642	735,199	785,199	2,480,199	1,315,199	415,199	335,199	538,245	26,742,082
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$0	$0	$0	$0	$0	$20,137,642	$20,872,842	$21,658,041	$24,138,240	$25,453,439	$25,868,639	$26,203,838	$26,742,082	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	(77,194)	(157,207)	(240,229)	(332,759)	(430,331)	(529,494)	(629,942)	
4.	CWIP - Non-Interest Bearing	13,231,646	14,916,846	16,552,045	17,687,244	18,752,443	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$13,231,646	14,916,846	16,552,045	17,687,244	18,752,443	20,137,642	20,795,648	21,500,834	23,898,011	25,120,680	25,438,308	25,674,344	26,112,140	
6.	Average Net Investment		14,074,246	15,734,445	17,119,644	18,219,844	19,445,043	20,466,645	21,148,241	22,699,422	24,509,346	25,279,494	25,556,326	25,893,242	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$73,653	$82,341	$89,590	$95,347	$101,759	$107,105	$110,672	$118,790	$128,261	$132,292	$133,741	$135,504	$1,309,055
	b. Debt Component Grossed Up For Taxes (C)		19,180	21,442	23,330	24,829	26,499	27,891	28,820	30,934	33,400	34,450	34,827	35,286	340,888
8.	Investment Expenses														
	a. Depreciation (D)		0	0	0	0	0	77,194	80,013	83,022	92,530	97,572	99,163	100,448	629,942
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		92,833	103,783	112,920	120,176	128,258	212,190	219,505	232,746	254,191	264,314	267,731	271,238	2,279,885
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		92,833	103,783	112,920	120,176	128,258	212,190	219,505	232,746	254,191	264,314	267,731	271,238	2,279,885
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		92,833	103,783	112,920	120,176	128,258	212,190	219,505	232,746	254,191	264,314	267,731	271,238	2,279,885
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$92,833	$103,783	$112,920	$120,176	$128,258	$212,190	$219,505	$232,746	$254,191	$264,314	$267,731	$271,238	$2,279,885

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.40
(B) Line 6 x 6.2798% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is 4.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Section 316(b) Impingement Mortality
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$483,000	$350,572	$331,138	$398,007	$134,000	$4,000	$4,000	$657	$0	$0	$0	$0	$1,705,374
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	12,871,825	13,354,825	13,705,397	14,036,535	14,434,542	14,568,542	14,572,542	14,576,542	14,577,199	14,577,199	14,577,199	14,577,199	14,577,199	
5.	Net Investment (Lines 2 + 3 + 4)	$12,871,825	13,354,825	13,705,397	14,036,535	14,434,542	14,568,542	14,572,542	14,576,542	14,577,199	14,577,199	14,577,199	14,577,199	14,577,199	
6.	Average Net Investment		13,113,325	13,530,111	13,870,966	14,235,539	14,501,542	14,570,542	14,574,542	14,576,871	14,577,199	14,577,199	14,577,199	14,577,199	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$68,624	$70,805	$72,589	$74,497	$75,889	$76,250	$76,271	$76,283	$76,285	$76,285	$76,285	$76,285	$896,348
	b. Debt Component Grossed Up For Taxes (C)		17,870	18,438	18,903	19,399	19,762	19,856	19,861	19,865	19,865	19,865	19,865	19,865	233,414
8.	Investment Expenses														
	a. Depreciation (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		86,494	89,243	91,492	93,896	95,651	96,106	96,132	96,148	96,150	96,150	96,150	96,150	1,129,762
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		86,494	89,243	91,492	93,896	95,651	96,106	96,132	96,148	96,150	96,150	96,150	96,150	1,129,762
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		86,494	89,243	91,492	93,896	95,651	96,106	96,132	96,148	96,150	96,150	96,150	96,150	1,129,762
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$86,494	$89,243	$91,492	$93,896	$95,651	$96,106	$96,132	$96,148	$96,150	$96,150	$96,150	$96,150	$1,129,762

Notes:
(A) Applicable depreciable base for Big Bend; accounts TBD depending on type of plant added
(B) Line 6 x 6.2798% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is TBD depending on type of plant added
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Return on Capital Investments, Depreciation and Taxes
For Project: Bayside 316(b) Compliance
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$329,973	$60,742	$60,742	$599,204	$60,742	$1,406,896	$60,742	$60,742	$60,742	$1,893,782	$547,628	$547,628	$5,689,564
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	329,973	390,715	451,457	1,050,661	1,111,403	2,518,299	2,579,041	2,639,783	2,700,525	4,594,307	5,141,936	5,689,564	
5.	Net Investment (Lines 2 + 3 + 4)	$0	329,973	390,715	451,457	1,050,661	1,111,403	2,518,299	2,579,041	2,639,783	2,700,525	4,594,307	5,141,936	5,689,564	
6.	Average Net Investment		164,987	360,344	421,086	751,059	1,081,032	1,814,851	2,548,670	2,609,412	2,670,154	3,647,416	4,868,122	5,415,750	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$863	$1,886	$2,204	$3,930	$5,657	$9,497	$13,338	$13,655	$13,973	$19,088	$25,476	$28,342	$137,909
	b. Debt Component Grossed Up For Taxes (C)		225	491	574	1,024	1,473	2,473	3,473	3,556	3,639	4,971	6,634	7,380	35,913
8.	Investment Expenses														
	a. Depreciation (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		1,088	2,377	2,778	4,954	7,130	11,970	16,811	17,211	17,612	24,059	32,110	35,722	173,822
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		1,088	2,377	2,778	4,954	7,130	11,970	16,811	17,211	17,612	24,059	32,110	35,722	173,822
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		1,088	2,377	2,778	4,954	7,130	11,970	16,811	17,211	17,612	24,059	32,110	35,722	173,822
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$1,088	$2,377	$2,778	$4,954	$7,130	$11,970	$16,811	$17,211	$17,612	$24,059	$32,110	$35,722	$173,822

Notes:
(A) Applicable depreciable base for Big Bend; accounts TBD depending on type of plant added
(B) Line 6 x 6.2798% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6353% x 1/12
(D) Applicable depreciation rate is TBD depending on type of plant added
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
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Project Title: Big Bend Unit 3 Flue Gas Desulfurization Integration

Project Description:

This project involved the integration of Big Bend Unit 3 flue gases into the Big Bend Unit 4 Flue Gas Desulfurization ("FGD") system. The integration was accomplished by installing interconnecting ductwork between Unit 3 precipitator outlet ducts and the Unit 4 FGD inlet duct. The Unit 4 FGD outlet duct was interconnected with the Unit 3 chimney via new ductwork and a new stack breaching. New ductwork, linings, isolation dampers, support steel, and stack annulus pressurization fans were procured and installed. Modifications to the materials handling systems and controls were also necessary.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021, is $903,783 compared to the original projection of $906,095.

The actual/estimated O&M expense for the period January 2021 through December 2021 is $0 and did not vary from the original projection.

Progress Summary: This project was approved by the Commission in Docket No. 19960688-EI, Order No. PSC-1996-1048-FOF-EI, issued August 14, 1996. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $956,797.

There are not any projected O&M costs for the period January 2022 through December 2022.

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Project Title: Big Bend Units 1 & 2 Flue Gas Conditioning

Project Description:

The existing electrostatic precipitators were not designed for the range of fuels needed for compliance with the Clean Air Act Amendments ("CAAA"). Flue gas conditioning was required to assure operation of the generating units in accordance with applicable permits and regulations. This equipment is still required to ensure compliance with the CAAA in the event the FGD system on Units 1 & 2 is not operating.

The project involved the addition of molten sulfur unloading, storage and conveying to sulfur burners and catalytic converters where SO_2 is converted to SO_3. The control and injection system then injects this into the ductwork ahead of the electrostatic precipitators.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $192,990 compared to the original projection of $193,042.

The actual/estimated O&M expense for the period January 2021 through December 2021 is $0 and did not vary from the original projection.

Progress Summary: This project was approved by the Commission in Docket No. 19960688-EI, Order No. PSC-1996-1048-FOF-EI, issued August 14, 1996. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $79,390.

There are not any O&M costs projected for the period of January 2022 through December 2022.

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Project Title: Big Bend Unit 4 Continuous Emissions Monitors

Project Description:

Continuous emissions monitors ("CEMs") were installed on the flue gas inlet and outlet of Big Bend Unit 4 to monitor compliance with the CAAA requirements. The monitors are capable of measuring, recording and electronically reporting SO_2, NO_x and volumetric gas flow out of the stack. The project consisted of monitors, a CEM building, the CEMs control and power cables to supply a complete system.

40 CFR Part 75 includes the general requirements for the installation, certification, operation, and maintenance of CEMs and specific requirements for the monitoring of pollutants, opacity, and volumetric flow. These regulations are very comprehensive and specific as to the requirements for CEMs, and in essence, they define the components needed and their configuration.

Project Accomplishment:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $45,522 compared to the original projection of $45,598.

Progress Summary: This project was approved by the Commission in Docket No. 19960688-EI, Order No. PSC-1996-1048-FOF-EI, issued August 14, 1996. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $40,993.

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Project Title: Big Bend Unit 1 Classifier Replacement

Project Description:

The boiler modifications at Big Bend Unit 1 are part of Tampa Electric's NO_X compliance strategy for Phase II of the CAAA. The classifier replacements optimize coal fineness by providing a uniform particle size. This finer classification, combined with the equalized distribution of coal to outlet pipes and furnaces, enables a uniform, staged combustion. As a result, firing systems operate at lower NO_X levels.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $69,128 compared to the original projection of $69,201.

Progress Summary: This project was approved by the Commission in Docket No. 19980007-EI, Order No. PSC-1998-1764-FOF-EI, issued December 31, 1998. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $80,286.

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Project Title: Big Bend Unit 2 Classifier Replacement

Project Description:

The boiler modifications at Big Bend Unit 2 are part of Tampa Electric's NO_X compliance strategy for Phase II of the CAAA. The classifier replacements optimize coal fineness by providing a more uniform particle size. This finer classification, combined with the equalized distribution of coal to outlet pipes and furnaces, enables a uniform, staged combustion. As a result, firing systems operate at lower NO_X levels.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $50,424 compared to the original projection of $50,482.

Progress Summary: This project was approved by the Commission in Docket No. 19980007-EI, Order No. PSC-1998-1764-FOF-EI, issued December 31, 1998. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $53,351.

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Project Title: Big Bend Units 1 & 2 FGD

Project Description:

The Big Bend Units 1 & 2 FGD system consists of equipment capable of removing SO_2 from the flue gas generated by the combustion of coal. The FGD was installed in order to comply with Phase II of the CAAA. Compliance with Phase II was required by January 1, 2000. The CAAA impose SO_2 emission limits on existing steam electric units with an output capacity of greater than 25 megawatts and all new utility units. Tampa Electric conducted an exhaustive analysis of options to comply with Phase II of the CAAA that culminated in the selection of the FGD project to serve Big Bend Units 1 & 2.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $5,431,446 compared to the original projection of $5,440,931.

The actual/estimated O&M costs for the period January 2021 through December 2021 are $8,966 compared to the original estimate of $0, resulting in a variance of 100 percent. The variance is due to Big Bend Unit 2 operating the FGD system when generating by natural gas which was not originally anticipated but is required for cooling gases to protect system ductwork.

Progress Summary: This project was approved by the Commission in Docket No. 19980693-EI, Order No. PSC-1999-0075-FOF-EI, issued January 11, 1999. The project is complete and in service.

Projections: A portion of these assets will be transferred to the Clean Energy Transition Mechanism effective January 1, 2022 where the net book value will be amortized and recovered from customers over a 15-year period in accordance with the 2021 Agreement. As a result, there will no longer be estimated depreciation or return for this portion of the project, tracked and recovered through the ECRC, effective January 1, 2022. Regarding the remaining assets, the estimated depreciation plus return for the period January 2022 through December 2022 is $1,828,248.

There are not any O&M costs projected for the period January 2022 through December 2022.

Tampa Electric Company
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Description and Progress Report for
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Project Title: Big Bend Section 114 Mercury Testing Platform

Project Description:

The Mercury Emissions Information Collection Effort is mandated by the EPA. The EPA asserts that Section 114 of the CAAA grants EPA the authority to request the collection of information necessary for it to study whether it is appropriate and necessary to develop performance of emission standards for electric utility steam generating units.

In a letter dated November 25, 1998, Tampa Electric was notified by the EPA that, pursuant to Section 114 of the CAAA, the company was required to periodically sample and analyze coal shipments for mercury and chlorine content during the period January 1, 1999 through December 31, 1999.

In addition to coal sampling, stack testing and analyses are also required. Tampa Electric received a second letter from EPA, dated March 11, 1999, requiring Tampa Electric to perform specialized mercury testing of the inlet and outlet of the last emission control device installed for Big Bend Units 1, 2 or 3, and Polk Unit 1 as part of the mercury data collection. Part of the cost incurred to perform the stack testing is due to the need to construct special test facilities at the Big Bend stack testing location to meet EPA's testing requirements.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $7,943 compared to the original projection of $7,958.

Progress Summary: This project was approved by the Commission in Docket No. 19990976-EI, Order No. PSC-1999-2103-PAA-EI, issued October 25, 1999. The project was placed in service in December 1999 and completed in May 2000.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $8,050.

Tampa Electric Company
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Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend FGD Optimization and Utilization

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to optimize the SO_2 removal efficiency and operations of the Big Bend Units 1, 2 and 3 FGD systems. Tampa Electric performed activities in three key areas to improve the performance and reliability of the Big Bend Units 1, 2 and 3 FGD systems. The majority of the improvements required on the Unit 3 tower module included the tower piping, nozzle and internal improvements, ductwork improvements, electrical system reliability improvements, tower control improvements, dibasic acid system improvements, booster fan reliability, absorber system improvements, quencher system improvements, and tower demister improvements. Big Bend Units 1 and 2 FGD system improvements included additional preventative maintenance, oxidation air control improvements, and tower water, air reagent and start-up piping upgrades. In order to ensure reliability of the FGD systems, improvements to the common limestone supply, gypsum de-watering stack reliability and wastewater treatment plant were also performed.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $1,503,371 compared to the original projection of $1,507,233.

Progress Summary: This project was approved by the Commission in Docket No. 20000685-EI, Order No. PSC-2000-1906-PAA-EI, issued October 18, 2000. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $1,589,173.

Tampa Electric Company
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Project Title: Big Bend PM Minimization and Monitoring

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to develop a Best Operational Practices ("BOP") study to minimize emissions from each electrostatic precipitator ("ESP") at Big Bend, as well as perform a best available control technology ("BACT") analysis for the upgrade of each existing ESP. The company is also required to install and operate particulate matter continuous emission monitors on Big Bend Units 1, 2 and 3 FGD systems. Tampa Electric identified improvements that were necessary to optimize ESP performance such as modifications to the turning vanes and precipitator distribution plates, and upgrades to the controls and software system of the precipitators. Tampa Electric incurred costs associated with the recommendations of the BOP study and the BACT analysis in 2001 and continues to make O&M and capital expenditures.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $1,680,736 compared to the original projection of $1,684,675.

The actual/estimated O&M costs for the period January 2021 through December 2021 are $218,747 compared to the original projection of $252,000, resulting in a variance of 13.2 percent. This variance is due to Big Bend Units operating less than projected. As a result, less maintenance is required.

Progress Summary: This project was approved by the Commission in Docket No. 20001186-EI, Order No. PSC-2000-2104-PAA-EI, issued November 6, 2000. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $1,733,829.

The estimated O&M costs for the period January 2022 through December 2022 are $259,560.

Tampa Electric Company
Environmental Cost Recovery Clause
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Project Title: Big Bend NO_x Emissions Reduction

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to spend up to $3 million with the goal to reduce NO_x emissions at Big Bend Station. By 2002, the Consent Decree required the company to achieve at least a 30 percent reduction beyond 1998 NO_x emission levels for Big Bend Units 1 and 2 and at least a 15 percent reduction in NO_x emissions from Big Bend Unit 3. Tampa Electric identified and completed projects that were the first steps to decrease NO_x emissions in these units such as burner and windbox modifications and the installation of a neural network system on each of the Big Bend units.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $485,706 compared to the original projection of $487,214.

The actual/estimated O&M costs for the period January 2021 through December 2021 are $2,950 compared to the original projection of $2,028, resulting in a variance of 45.5 percent. This variance is due to maintenance required on a secondary damper that was more than originally projected.

Progress Summary: This project was approved by the Commission in Docket No. 20001186-EI, Order No. PSC-2000-2104-PAA-EI, issued November 6, 2000. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $505,339.

The estimated O&M costs projected for the period January 2022 through December 2022 are $2,089.

Tampa Electric Company
Environmental Cost Recovery Clause
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Project Title: Big Bend Fuel Oil Tank No. 1 Upgrade

Project Description:

The Big Bend Fuel Oil Tank No. 1 Upgrade is a 500,000 gallon field-erected fuel storage tank that is required to meet the requirements of FDEP Rule 62-762 as an existing field-erected above ground storage tank containing a regulated pollutant (diesel fuel). The rule required various modifications and a complete internal inspection by the end of 1999.

The scope of work for this project included cleaning and inspecting the tank in accordance with API 653 specifications, coating the internal floor plus 30 inches up the tank wall, installing an AEI Segundo bottom to the tank as well as installing a leak detection system, installing a spill containment for piping fittings and valves surrounding the tank, installing a new truck unloading facility and spill containment for the truck unloading facility, installing level instrumentation for overfill protection, installing secondary containment for below ground piping or reroute to above ground, and conducting a tank closure assessment.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $63,892 compared to the original projection of $63,896.

Progress Summary: This project was approved by the Commission in Docket No. 19980007-EI, Order No. PSC-1998-0408-FOF-EI, issued March 18, 1998. The project has been retired.

Projections: The investment was fully amortized in 2021. There is neither depreciation nor return for the period January 2022 through December 2022.

Tampa Electric Company
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Project Title: Big Bend Fuel Oil Tank No. 2 Upgrade

Project Description:

The Big Bend Fuel Oil Tank No. 2 is a 4,200,000 gallon field-erected fuel storage tank that is required to meet the requirements of FDEP Rule 62-762 as an existing field-erected above ground storage tank containing a regulated pollutant (diesel fuel). The rule required various modifications and a complete internal inspection by the end of 1999.

The scope of work for this project included cleaning and inspecting the tank in accordance with API 653 specifications, coating the internal floor plus 30 inches up the tank wall, installing an AEI Segundo bottom to the tank as well as installing a leak detection system, installing a spill containment for piping fittings and valves surrounding the tank, installing a new truck unloading facility and spill containment for the truck unloading facility, installing level instrumentation for overfill protection, installing secondary containment for below ground piping or reroute to above ground, and conducting a tank closure assessment.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $105,079 compared to the original projection of $105,098.

Progress Summary: This project was approved by the Commission in Docket No. 19980007-EI, Order No. PSC-1998-0408-FOF-EI, issued March 18, 1998. The project has been retired.

Projections: The investment was fully amortized in 2021. There is neither depreciation nor return for the period January 2022 through December 2022.

Tampa Electric Company
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Project Title: SO_2 Emission Allowances

Project Description:

The acid rain control title of the CAAA sets forth a comprehensive regulatory mechanism designed to control acid rain by limiting sulfur dioxide emissions by electric utilities. The CAAA requires reductions in SO_2 emissions in two phases. Phase I began on January 1, 1995 and applies to 110 mostly coal-fired utility plants containing about 260 generating units. These plants are owned by some 40 jurisdictional utility systems that are expected to reduce annual SO_2 emissions by as much as 4.5 million tons. Phase II began on January 1, 2000, and applies to virtually all existing steam-electric generating utility units with capacity exceeding 25 megawatts and to new generating utility units of any size. The EPA issues to the owners of generating units allowances (defined as an authorization to emit, during or after a specified calendar year, one ton of SO_2) equal to the number of tons of SO_2 emissions authorized by the CAAA. EPA does not assess a charge for the allowances it awards.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated return on average net working capital for the period January 2021 through December 2021 is ($2,688) compared to the original projection of ($2,688).

The actual/estimated O&M costs for the period January 2021 through December 2021 are $41 compared to the original projection of $15. The variance is not material.

Progress Summary: SO_2 emission allowances are being used by Tampa Electric to meet compliance standards for Phase I of the CAAA.

Project Projections: The estimated return on average net working capital for the period January 2022 through December 2022 is ($2,712).

The estimated O&M costs for the period January 2022 through December 2022 are $41.

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Project Title: National Pollutant Discharge Elimination System ("NPDES") Annual Surveillance Fees

Project Description:

Chapter 62-4.052, Florida Administrative Code ("F.A.C."), implements the annual regulatory program and surveillance fees for wastewater permits. These fees are in addition to the application fees described in Rule 62-4.050, F.A.C. Tampa Electric's Big Bend, Polk, and Bayside Stations are affected by this rule.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M costs for the period January 2021 through December 2021 is $34,500 compared to the original projection of $23,500. The variance is 46.8 percent and is due to Polk NPDES fees not being included in setting the original projection.

Progress Summary: NPDES Surveillance fees are paid annually for the prior year.

Projections: The estimated O&M costs for the period January 2022 through December 2022 are $34,500.

Tampa Electric Company
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Project Title: Gannon Thermal Discharge Study

Project Description:

This project was a direct requirement from the FDEP in conjunction with the renewal of Tampa Electric's Industrial Wastewater Facility Permit under the provisions of Chapter 403, Florida Statutes, and applicable rules of the Florida Administrative Code, which constitute authorization for the company's Gannon Station facility to discharge to waters of the State under the NPDES. The FDEP permit is Permit No. FL0000809. Specifically, Tampa Electric was required to perform a 316(a) determination for Gannon Station to ensure the protection and propagation of a balanced, indigenous population of shellfish, fish, and wildlife within the primary area of study. The project had two facets: 1) developing a plan of study and identified the thermal plume, and 2) implemented the plan of study through appropriate sampling to make the determination if any adverse impacts are occurring.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M expense for the period January 2021 through December 2021 is $0 and did not vary from the original projection.

Progress Summary: This project was approved by the Commission in Docket No. 20010593-EI, Order No. PSC-2001-1847-PAA-EI on September 4, 2001. The project is complete and in service.

Projections: There are not any O&M costs projected for the period January 2022 through December 2022.

Tampa Electric Company
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Project Title: Polk NO_x Emissions Reduction

Project Description:

This project was designed to meet a lower NO_x emissions limit established by the FDEP for Polk Unit 1 by July 1, 2005. The lower limit of 15 parts per million by volume dry basis at 15 percent O_2 is specified in FDEP Permit No. PSD-FL-194F issued February 5, 2002. The project consisted of two phases: 1) the humidification of syngas through the installation of a syngas saturator; and 2) the modification of controls and the installation of additional guide vanes to the diluent nitrogen compressor.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $103,219 compared to the original projection of $103,428.

The actual/estimated O&M costs for the period January 2021 through December 2021 is $595 compared to the original projection of $0. The variance is 100 percent and is due to costs being charged to the project work order in error. The amount will be reversed in July 2021.

Progress Summary: This project was approved by the Commission in Docket No. 20020726-EI, Order No. PSC-2002-1445-PAA-EI on October 21, 2002. The project is complete and in service.

Project Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $109,983.

There are not any O&M costs projected for the period of January 2022 through December 2022.

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Project Title: Bayside SCR Consumables

Project Description:

This project is necessary to achieve the NO_x emissions limit of 3.5 parts per million established by the FDEP Consent Final Judgment and the EPA Consent Decree for the natural gas-fired Bayside Power Station. To achieve this NO_x limit, the installation of selective catalytic reduction (SCR) systems is required. An SCR system requires consumable goods – primarily anhydrous ammonia – to be injected into the catalyst bed in order to achieve the required NO_x emissions limit. Principally, the project was designed to capture the cost of consumable goods necessary to operate the SCR systems.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M costs for the period January 2021 through December 2021 are $139,173 compared to the original projection of $119,000. The variance is 17 percent and is due to Bayside Station generation being greater than originally projected, leading to the need for more consumables.

Progress Summary: This project was approved by the Commission in Docket No. 20021255-EI, Order No. PSC-2003-0469-PAA-EI, issued April 4, 2003. Annual O&M expenses will continue to be incurred.

Projections: The estimated O&M costs for the period January 2022 through December 2022 are projected to be $151,000.

Tampa Electric Company
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Project Title: Big Bend Unit 4 Separated Overfire Air ("SOFA")

Project Description:

This project is necessary to assist in achieving the NO_x emissions limit established by the FDEP Consent Final Judgment and the EPA Consent Decree for Big Bend Unit 4. A SOFA system stages secondary combustion air to prevent NO_x formation that would otherwise require removal by post-combustion technology. In-furnace combustion control through a SOFA system is the most cost-effective means to reduce NO_x emissions prior to the application of these technologies. Costs associated with the SOFA system entailed capital expenditures for equipment installation and subsequent annual maintenance.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $185,038 compared to the original projection of $185,486.

The actual/estimated O&M expense for the period January 2021 through December 2021 is $0 and did not vary from the original projection.

Progress Summary: This project was approved by the Commission in Docket No. 20030226-EI, Order No. PSC-2003-0684-PAA-EI, issued June 6, 2003. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $187,341.

There are not any O&M costs projected for the period of January 2022 through December 2022.

Tampa Electric Company
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Description and Progress Report for
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Project Title: Big Bend Unit 1 Pre-SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2021 through 2022. Thus, the installation of cost-effective SCR technology on the generating units was necessary to meet NO_x emissions requirements. This project was a necessary precursor to an SCR system designed to reduce inlet NO_x concentrations to the SCR system thereby mitigating overall capital and O&M costs. The Big Bend Unit 1 Pre-SCR technologies included a neural network system, secondary air controls and windbox modifications.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $124,987 compared to the original projection of $125,229.

The actual/estimated O&M expense for the period January 2021 through December 2021 is $0 and did not vary from the original projection.

Progress Summary: This project was approved by the Commission in Docket No. 20040750-EI, Order No. PSC-2004-0986-CO-EI, issued October 11, 2004. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $139,318.

There are not any O&M costs projected for the period of January 2022 through December 2022.

Tampa Electric Company
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Project Title: Big Bend Unit 2 Pre-SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2021 through 2022. Thus, the installation of cost-effective SCR technology on the generating units was necessary to meet NO_x emissions requirements. This project was a necessary precursor to an SCR system designed to reduce inlet NO_x concentrations to the SCR system thereby mitigating overall capital and O&M costs. The Big Bend Unit 2 Pre-SCR technologies included secondary air controls and windbox modifications.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $119,909 compared to the original projection of $120,162.

The actual/estimated O&M expense for the period January 2021 through December 2021 is $0 and did not vary from the original projection.

Progress Summary: This project was approved by the Commission in Docket No. 20040750-EI, Order No. PSC-2004-0986-CO-EI, issued October 11, 2004. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $124,963.

There are not any O&M costs projected for the period of January 2022 through December 2022.

Tampa Electric Company
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Project Title: Big Bend Unit 3 Pre-SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2021 through 2022. Thus, the installation of cost-effective SCR technology on the generating units was necessary to meet NO_x emissions requirements. This project was a necessary precursor to an SCR system designed to reduce inlet NO_x concentrations to the SCR system thereby mitigating overall capital and O&M costs. The Big Bend Unit 3 Pre-SCR technologies included a neutral network system, secondary air controls, windbox modifications and primary coal/air flow controls.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $216,230 compared to the original projection of $216,730.

The actual/estimated O&M expense for the period January 2021 through December 2021 is $0 and did not vary from the original projection.

Progress Summary: This project was approved by the Commission in Docket No. 20040750-EI, Order No. PSC-2004-0986-CO-EI, issued October 11, 2004. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $209,670.

There are not any O&M costs projected for the period of January 2022 through December 2022.

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Project Title: Clean Water Act Section 316(b) Phase II Study

Project Description:

This project was a direct requirement from the EPA to reduce impingement and entrainment of aquatic organisms related to the withdrawal of waters for cooling purposes through cooling water intake structures. The Phase II Rule requires that power plants meet certain criteria to comply with national performance standards for impingement and entrainment. Accordingly, Tampa Electric must develop its compliance strategies for its Bayside and Big Bend Stations and then submit these strategies for approval through a Comprehensive Demonstration Study to the FDEP.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M costs for the period January 2021 through December 2021 are $6,020 compared to the original projection of $45,000, resulting in a variance of -86.6 percent. This variance is due to the delay in receiving the NPDES permit. Once the permit is received, the costs will be incurred.

Progress Summary: This project was approved by the Commission in Docket No. 20041300-EI, Order No. PSC-2005-0164-PAA-EI, issued February 10, 2005.

Projections: The estimated O&M costs for the period January 2022 through December 2022 are $10,150.

Tampa Electric Company
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Project Title: Big Bend Unit 1 SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times. The installation of cost-effective SCR technology on the generating units was necessary to meet NO_x emissions requirements.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $7,151,546 compared to the original projection of $7,165,809.

The actual/estimated O&M expense for the period January 2021 through December 2021 is $0 and did not vary from the original projection.

Progress Summary: This project was approved by the Commission in Docket No. 20041376-EI, Order No. PSC-2005-0502-CO-EI, issued May 9, 2005. The project is complete and in service.

Projections: This asset will be transferred to the Clean Energy Transition Mechanism effective January 1, 2022 where the net book value will be amortized and recovered from customers over a 15-year period in accordance with the 2021 Agreement. As a result, there will no longer be estimated depreciation or return for this project, tracked and recovered through the ECRC, effective January 1, 2022.

There are not any O&M costs projected for the period January 2022 through December 2022.

Tampa Electric Company
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Description and Progress Report for
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Project Title: Big Bend Unit 2 SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times. The installation of cost-effective SCR technology on the generating units was necessary to meet NO_x emissions requirements.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $7,876,719 compared to the original projection of $7,893,828.

The actual/estimated O&M costs for the period January 2021 through December 2021 are $106,340 compared to the original projection of $122,020, resulting in a variance of -12.9 percent. This variance is due to current estimates of Big Bend Unit 2 SCR maintenance costs, while generating on natural gas, are expected to be lower than originally projected, along with less total generation than originally estimated.

Progress Summary: This project was approved by the Commission in Docket No. 20041376-EI, Order No. PSC-2005-0502-CO-EI, issued May 9, 2005. The project is complete and in service.

Projections: This asset will be transferred to the Clean Energy Transition Mechanism effective January 1, 2022 where the net book value will be amortized and recovered from customers over a 15-year period in accordance with the 2021 Agreement. As a result, there will no longer be estimated depreciation or return for this project, tracked and recovered through the ECRC, effective January 1, 2022.

There are not any O&M costs projected for the period January 2022 through December 2022.

Tampa Electric Company
Environmental Cost Recovery Clause
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Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 3 SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times. The installation of cost-effective SCR technology on the generating units was necessary to meet NO_x emissions requirements.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $6,415,803 compared to the original projection of $6,429,857.

The actual/estimated O&M costs for the period January 2021 through December 2021 are $542,672 compared to the original projection of $524,097, resulting in a variance of 3.5 percent.

Progress Summary: This project was approved by the Commission in Docket No. 20041376-EI, Order No. PSC-2005-0502-CO-EI, issued May 9, 2005. The project is complete and in service.

Projections: This asset will be transferred to the Clean Energy Transition Mechanism effective January 1, 2022 where the net book value will be amortized and recovered from customers over a 15-year period in accordance with the 2021 Agreement. As a result, there will no longer be estimated depreciation or return for this project, tracked and recovered through the ECRC, effective January 1, 2022.

The estimated O&M costs for the period January 2022 through December 2022 are $372,522.

Tampa Electric Company
Environmental Cost Recovery Clause
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Description and Progress Report for
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Project Title: Big Bend Unit 4 SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times. The installation of cost-effective SCR technology on the generating units was necessary to meet NO_x emissions requirements.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $5,168,642 compared to the original projection of $5,199,976.

The actual/estimated O&M costs for the period January 2021 through December 2021 are $893,479 compared to the original projection of $1,077,230, resulting in a variance of -17.1 percent. This variance is due to current estimates of Big Bend Unit 4 SCR maintenance costs, while generating on natural gas, are expected to be lower than originally projected, along with less total generation than originally projected.

Progress Summary: This project was approved by the Commission in Docket No. 20040750-EI, Order No. PSC-2004-0986-PAA-EI, issued October 11, 2004. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $4,955,963.

The estimated O&M costs for the period January 2022 through December 2022 are $1,397,376.

<u>Tampa Electric Company</u>
Environmental Cost Recovery Clause
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Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Arsenic Groundwater Standard Program

Project Description:
The Arsenic Groundwater Standard Program that is required by the Environmental Protection Agency and the Department of Environmental Protection became effective January 1, 2005. It requires regulated entities of the State of Florida to monitor the drinking water and groundwater Maximum Contaminant Level ("MCL") for arsenic under the federal rule known as the Safe Drinking Water Act.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M costs for the period January 2021 through December 2021 are $0 compared to the original projection of $36,000. This variance is due to the delay of groundwater monitoring work while awaiting Florida Department of Environmental Protection ("FDEP") approval of the company's plan. Once the permit is received, the costs will be incurred.

Progress Summary: This project was approved by the Commission in Docket No. 20050683-EI, Order No. PSC-2006-0138-PAA-EI, issued February 23, 2006. The project is complete and in service.

Projections: The estimated O&M costs for the period of January 2022 through December 2022 are $37,080.

Tampa Electric Company
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Description and Progress Report for
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Project Title: Big Bend Flue Gas Desulfurization ("FGD") System Reliability

Project Description:
The Big Bend FGD Reliability project is necessary to maintain the FGD system operations that are required by the Consent Decree. Tampa Electric is required to operate the FGD systems at Big Bend Station whenever coal is combusted in the units with few exceptions. The compliance dates for the strictest operational characteristics were January 1, 2011 for Big Bend Unit 3 and January 1, 2014 for Big Bend Units 1 and 2.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $2,007,420 compared to the original projection of $2,013,174.

Progress Summary: This project was approved by the Commission in Docket No. 20050598-EI, Order No. PSC-2006-0602-PAA-EI, issued July 10, 2006. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $2,108,118.

Tampa Electric Company
Environmental Cost Recovery Clause
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Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Mercury Air Toxics Standards ("MATS")

Project Description:
In March 2005, the Environmental Protection Agency ("EPA") promulgated the Clean Air Mercury Rule ("CAMR") and was later challenged in court. On February 8, 2008, the Circuit Court of Appeals for the District of Columbia vacated CAMR and ordered a new rule by March 2011. On December 11, 2011, the EPA issued a final version of the rule that applies to all coal and oil-fired electric generating units with a capacity of 25 MW or more and with a compliance deadline is April 16, 2015. The rule sets forth hazardous air pollutant standards ("HAP") for mercury, non-mercury metal HAPs and acid gasses.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $781,102 compared to the original projection of $783,036.

The actual/estimated O&M costs for the period January 2021 through December 2021 are $5,494 compared to the original projection of $3,000, resulting in a variance of 83.1 percent. This variance is due to higher cost of mercury traps used for stack testing than originally projected.

Progress Summary: This project was approved by the Commission in Docket No. 20120302-EI, Order No. PSC-2013-0191-PAA-EI, issued May 6, 2013. The project is in service.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is projected to be $799,392.

The estimated O&M costs for the period January 2022 through December 2022 are projected to be $2,000.

Tampa Electric Company
Environmental Cost Recovery Clause
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Project Title: Greenhouse Gas Reduction Program

Project Description:
On September 22, 2009, the EPA enacted a new rule for reporting Greenhouse Gas ("GHG") emissions from large sources and suppliers effective January 1, 2010 in preparation for the first annual GHG report, due March 31, 2011. The new rule is intended to collect accurate and timely emissions data to inform future policy decisions as set forth in the final rule for GHG emission reporting pursuant to the Florida Climate Protection Act, Chapter 403.44 of the Florida Statutes and the docket EPA-HQ-OAR2008-0508-054. The nationwide GHG emissions reduction rule will impact Tampa Electric's generation fleet, components of its transmission and distribution system as well as company service vehicles. According to the rule, the company began collecting greenhouse gas emissions data effective January 1, 2010 to establish a baseline inventory to report to the EPA.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M costs for the period January 2021 through December 2021 is $93,149 compared to the original projection of $93,528.

Progress Summary: This project was approved by the Commission in Docket No. 20090508-EI, Order No. PSC-2010-0157-PAA-EI, issued March 22, 2010. The project is complete and in service.

Projections: There are no O&M costs projected for the period January 2022 through December 2022.

Tampa Electric Company
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Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Gypsum Storage Facility

Project Description:

The Big Bend New Gypsum Storage Facility is necessary to maintain the FGD system operations that are required by the Consent Decree. Tampa Electric is required to operate the FGD systems in order to comply with the CAAA. Gypsum is a by-product of the FGD operations and Tampa Electric had been managing its gypsum inventory through marketing efforts to sell gypsum an existing storage facility. However, the existing storage facility was no longer sufficient to hold the entire gypsum inventory, and Tampa Electric needed an additional storage facility. The new storage facility covers approximately 27 acres and holds approximately 870,000 tons of gypsum.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $1,985,437 compared to the original projection of $1,991,084.

The actual/estimated O&M costs for the period January 2021 through December 2021 are $621,996 compared to the original projection of $1,177,899, resulting in a variance of -47.2 percent. The variance is due to a reduction in coal generation, compared to the original projection, so the amount of gypsum storage processing is reduced.

Progress Summary: This project was approved by the Commission in Docket No. 20110262-EI, Order No. PSC-2012-0493-PAA-EI, issued September 26, 2012. The project was placed in service in November 2014.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $2,010,667.

The estimated O&M costs for the period January 2022 through December 2022 are $1,213,236.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2022 through December 2022
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Coal Combustion Residuals ("CCR") Rule - Phase I & II

Project Description:

On April 17, 2015, the EPA published the CCR Rule with an effective date of October 19, 2015. The new rule requires the safe disposal of CCR in landfills and surface impoundments. Compliance activities include placing fugitive emissions dust control plans, increasing inspections, installing new groundwater monitoring wells, and closure of certain impoundments at CCR regulated management units.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 for Phase I and Phase II is $325,512 and $128,327 compared to the original projections of $362,933 and $328,169, respectively. The variances are due to timing differences in the project schedules when compared to the original projections. Because CCR removal activities have experienced project schedule delays early on, the final Project capital activities related to restoration of the site have been delayed. The project expenditures are still needed and will be incurred in the future.

The actual/estimated O&M costs for the period January 2021 through December 2021 for Phase I and Phase II are $763,222 and $5,813,349, respectively, compared to the original projections of $0 and $0, resulting in variances of 100% and 100%, respectively. The variances are due to timing differences in project schedules when compared to original projections. Another contributing factor to the increase is that more CCR material than originally estimated has been removed from the sites.

Progress Summary: Phase I was approved by the Commission in Docket No. 20150223-EI, Order No. PSC-2016-0068-PAA-EI, issued February 9, 2016. Phase II was approved by the Commission in Docket No. 20170168-EI, Order No. 2017-0483-PAA-EI, issued December 22, 2017.

Projections: Estimated depreciation plus return for the period January 2022 through December 2022 for Phase I and Phase II is $604,420 and $221,899, respectively.

The projected O&M costs for the period January 2022 through December 2022 for Phase I and Phase II are $930,000 and $0, respectively.

Tampa Electric Company
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Description and Progress Report for
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Project Title: Big Bend ELG Compliance

Project Description:

On November 3, 2015, the EPA published the ELG Rule with an effective date of January 4, 2016. The ELG Rule establish limits for wastewater discharges from flue gas desulfurization ("FGD") processes, fly ash and bottom ash transport water, leachate from ponds and landfills containing coal combustion residuals ("CCR"), gasification processes, and flue gas mercury controls. The final rule requires compliance as soon as possible after November 1, 2020, and no later than December 31, 2023. Tampa Electric hired an engineering consulting firm to perform the Big Bend ELG Compliance Study, completed in 2018, that concluded with a determination of the most appropriate ELG compliance measures identified.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 for Big Bend ELG Compliance is $439,715 compared to the original projection of $782,650. This variance is due to timing differences in the project schedule when compared to the original projection. Project activities have occurred more slowly than originally projected due to permitting delays. FDEP issued its permit regarding the project on April 10, 2020. The project expenditures are still needed and will be incurred in the future.

The actual/estimated O&M costs for the period January 2021 through December 2021 for Big Bend ELG Compliance are $0, compared to $4,800 in the original projection. This variance is due to timing differences in the project schedule when compared to the original projection. The costs will be incurred in the future.

Progress Summary: The Study program was approved by the Commission in Docket No. 20160027-EI, Order No. PSC-2016-0248-PAA-EI, issued June 28, 2016, and it is now complete. The Compliance Project was approved by the Commission in Docket No. 2018007-EI, Order No. PSC-2018-0594-FOF-EI, issued December 20, 2018.

Projections: The ELG Compliance program estimated depreciation plus return for the period January 2022 through December 2022 is $2,279,885.

The estimated O&M costs projected for the period of January 2022 through December 2022 are $4,944.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2022 through December 2022
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 1 Section 316(b) Impingement Mortality

Project Description:

In August 2014, the Environmental Protection Agency ("EPA") published their final rule regarding Section 316(b) of the Clean Water Act. The rule became effective in October 2014. The rule establishes requirements for cooling water intake structures ("CWIS") at existing facilities. Section 316(b) requires that the location, design, construction, and capacity of CWIS reflect the best technology available ("BTA") for minimizing adverse environmental impacts. For this project, compliance activities include modifying the existing Big Bend Unit 1 CWIS to reduce impingement mortality of affected living organisms.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2021 through December 2021 is $484,564, compared to the original projection of $452,502. This variance is due to timing differences in the project schedule when compared to the original projection. Earlier permit and material delivery logistic delays have been resolved and as such, project activities are getting back on track.

The actual/estimated O&M expense for the period January 2021 through December 2021 is $0 and did not vary from the original projection.

Progress Summary: This project was approved by the Commission in Docket No. 2018007-EI, Order No. PSC-2018-0594-FOF-EI, issued December 20, 2018.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $1,129,762.

There are not any O&M costs projected for the period of January 2022 through December 2022.

Tampa Electric Company
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Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Bayside 316(b) Compliance

Project Description:

In August 2014, the Environmental Protection Agency ("EPA") published their final rule regarding Section 316(b) of the Clean Water Act. The rule became effective in October 2014. The rule establishes requirements for cooling water intake structures ("CWIS") at existing facilities. Section 316(b) requires that the location, design, construction, and capacity of CWIS reflect the best technology available ("BTA") for minimizing adverse environmental impacts. For this project, compliance activities include modifying the existing Bayside Station CWIS to reduce impingement mortality of affected living organisms.

Project Accomplishments:

Fiscal Expenditures: There were no actual/estimated capital or O&M expenditures included in the ECRC for this project as it was not yet approved by the Commission when the ECRC Actual/Estimated True-up filing was submitted, on July 30, 2021.

Progress Summary: This project was approved by the Commission in Docket No. 20210087-EI, Order No. PSC-2021-0356-FOF-EI, issued September 15, 2021.

Projections: The estimated depreciation plus return for the period January 2022 through December 2022 is $173,822.

There are not any O&M costs projected for the period of January 2022 through December 2022.

Form 42 - 6P

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2022 to December 2022

Rate Class	(1) Average 12 CP Load Factor at Meter (%)	(2) Projected Sales at Meter (MWh)	(3) Effective Sales at Secondary Level (MWh)	(4) Projected Avg 12 CP at Meter (MW)	(5) Demand Loss Expansion Factor	(6) Energy Loss Expansion Factor	(7) Projected Sales at Generation (MWh)	(8) Projected Avg 12 CP at Generation (MW)	(9) Percentage of MWh Sales at Generation (%)	(10) Percentage of 12 CP Demand at Generation (%)	(11) 12 CP & 1/13 Allocation Factor (%)
RS	52.64%	9,728,165	9,728,165	2,110	1.07440	1.05326	10,246,279	2,267	49.26%	59.22%	58.45%
GS, CS	60.60%	953,392	953,392	180	1.07440	1.05324	1,004,152	193	4.83%	5.04%	5.02%
GSD	75.88%	7,090,680	7,090,680	1,067	1.07343	1.05213	7,460,330	1,145	35.87%	29.91%	30.37%
GSLDPR, SBLDPR	99.91%	1,193,640	1,193,640	136	1.04485	1.02672	1,225,538	142	5.89%	3.71%	3.88%
GSLDSU/SBLDSU	108.11%	735,184	735,184	78	1.02666	1.01449	745,836	80	3.59%	2.09%	2.21%
LS1, LS2	903.21%	110,703	110,703	1	1.07440	1.05326	116,599	1	0.56%	0.03%	0.07%
TOTAL *		19,811,763	19,811,763	3,572			20,798,734	3,828	100%	100%	100%

Notes:
(1) Average 12 CP load factor based on 2022 Projected calendar data
(2) Projected MWh sales for the period January 2022 to December 2022
(3) Effective sales at secondary level for the period January 2022 to December 2022.
(4) Column 2 / (Column 1 x 8760)
(5) Based on 2022 projected demand losses.
(6) Based on 2022 projected energy losses.
(7) Column 2 x Column 6
(8) Column 4 x Column 5
(9) Column 7 / Total Column 7
(10) Column 8 / Total Column 8
(11) Column 9 x1/13 + Column 10 x 12/13

* Totals on this schedule may not foot due to rounding

Form 42 - 7P

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2022 to December 2022

Rate Class	(1) Percentage of MWh Sales at Generation (%)	(2) 12 CP & 1/13 Allocation Factor (%)	(3) Energy-Related Costs ($)	(4) Demand-Related Costs ($)	(5) Total Environmental Costs ($)	(6) Projected Sales at Meter (MWh)	(7) Effective Sales at Secondary Level (MWh)	**(8) Environmental Cost Recovery Factors (¢/kWh)**
RS	49.26%	58.45%	10,752,976	2,679,849	13,432,825	9,728,165	9,728,165	0.138
GS, CS	4.83%	5.02%	1,054,342	230,160	1,284,502	953,392	953,392	0.135
GSD, SBF	35.87%	30.37%	7,830,071	1,392,421	9,222,492	7,090,680	7,086,906	
Secondary								0.130
Primary								0.129
Transmission								0.128
GSLDPR	5.89%	3.88%	1,285,730	177,892	1,463,622	1,193,640	1,193,640	0.123
GSLDSU	3.59%	2.21%	783,662	101,325	884,987	735,184	735,184	0.120
LS1, LS2	0.56%	0.07%	122,243	3,209	125,452	110,703	110,703	0.113
TOTAL *	100.00%	100.00%	21,829,024	4,584,857	26,413,881	19,811,763	19,807,990	0.133

* Totals on this schedule may not foot due to rounding

Notes:
(1) From Form 42-6P, Column 9
(2) From Form 42-6P, Column 11
(3) Column 1 x Total Energy Jurisdictional Dollars from Form 42-1P, line 5
(4) Column 2 x Total Demand Jurisdictional Dollars from Form 42-1P, line 5
(5) Column 3 + Column 4
(6) From Form 42-6P, Column 2
(7) From Form 42-6P, Column 3
(8) Column 5 / Column 7 x 10

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2022 to December 2022

Form 42 - 8P

Calculation of Revenue Requirement Rate of Return
(in Dollars)

	(1) Jurisdictional Rate Base 2022 Adj. FESR *with Normalization* ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 2,799,863	35.02%	4.17%	1.4604%
Short Term Debt	237,124	2.97%	1.01%	0.0300%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	91,410	1.14%	2.44%	0.0279%
Common Equity	3,646,406	45.61%	9.95%	4.5381%
Accum. Deferred Inc. Taxes & Zero Cost ITC's	954,275	11.94%	0.00%	0.0000%
Deferred ITC - Weighted Cost	265,755	3.32%	7.65%	0.2543%
Total	$ 7,994,834	100.00%		6.31%

ITC split between Debt and Equity:

Long Term Debt	$ 2,799,863	Long Term Debt	46.00%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	3,646,406	Equity - Common	54.00%
Total	$ 6,446,269	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = 0.2543% * 46.00%	0.1170%
Equity = 0.2543% * 54.00%	0.1373%
Weighted Cost	0.2543%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.5381%
Deferred ITC - Weighted Cost	0.1373%
	4.6754%
Times Tax Multiplier	1.34315
Total Equity Component	6.2798%

Total Debt Cost Rate:

Long Term Debt	1.4604%
Short Term Debt	0.0300%
Customer Deposits	0.0279%
Deferred ITC - Weighted Cost	0.1170%
Total Debt Component	1.6353%
Total Cost of Capital	7.9151%

Notes:
Column (1) - Per Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology.
Column (2) - Column (1) / Total Column (1)
Column (3) - Per Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology..
Column (4) - Column (2) x Column (3)

TAMPA ELECTRIC COMPANY
DOCKET NO. 20210007-EI
FILED: 10/01/2021

EXHIBIT TO THE TESTIMONY OF M. ASHLEY SIZEMORE

DOCUMENT NO. 2

TAMPA ELECTRIC'S ENVIRONMENTAL COST RECOVERY

PROJECTION

JANUARY 2022 THROUGH DECEMBER 2022

2021 SETTLEMENT - COST ALLOCATION BASELINE

Form 42 - 1E

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021
(in Dollars)

Line		Period Amount
1.	Over/(Under) Recovery for the Current Period (Form 42-2E, Line 5)	$21,124,621
2.	Interest Provision (Form 42-2E, Line 6)	34,212
3.	Sum of Current Period Adjustments (Form 42-2E, Line 10)	0
4.	Current Period True-Up Amount to be Refunded/(Recovered) In the Projection Period January 2022 to December 2022 (Lines 1 + 2 + 3)	$21,158,833

Form 42 - 2E

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Current Period True-Up Amount
(in Dollars)

Line	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1. ECRC Revenues (net of Revenue Taxes)	$4,084,708	$3,662,094	$3,642,808	$3,959,659	$4,362,891	$5,015,784	$5,103,097	$5,071,141	$5,310,054	$4,802,861	$4,025,337	$3,828,643	$52,869,078
2. True-Up Provision	(321,105)	(321,105)	(321,105)	(321,105)	(321,105)	(321,105)	(321,105)	(321,105)	(321,105)	(321,105)	(321,105)	(321,106)	(3,853,261)
3. ECRC Revenues Applicable to Period (Lines 1 + 2)	3,763,603	3,340,989	3,321,703	3,638,554	4,041,786	4,694,679	4,781,992	4,750,036	4,988,949	4,481,756	3,704,232	3,507,537	49,015,817
4. Jurisdictional ECRC Costs													
a. O & M Activities (Form 42-5E, Line 9)	1,247,596	569,096	1,907,372	1,258,012	1,440,778	1,146,917	453,640	250,262	249,262	246,415	247,262	234,080	9,250,692
b. Capital Investment Projects (Form 42-7E, Line 9)	1,515,365	1,517,956	1,523,729	1,528,521	1,528,059	1,531,713	1,540,694	1,550,945	1,565,318	1,590,945	1,620,213	1,627,045	18,640,503
c. Total Jurisdictional ECRC Costs	2,762,961	2,087,052	3,431,101	2,786,533	2,968,837	2,678,630	1,994,334	1,801,207	1,814,580	1,837,360	1,867,475	1,861,125	27,891,195
5. Over/(Under) Recovery (Line 3 - Line 4c)	1,000,642	1,253,937	(109,398)	852,021	1,072,949	2,016,049	2,787,658	2,948,829	3,174,369	2,644,396	1,836,757	1,646,412	21,124,621
6. Interest Provision (Form 42-3E, Line 10)	94	224	271	326	268	361	1,891	4,206	5,290	6,325	7,147	7,809	34,212
7. Beginning Balance True-Up & Interest Provision	(3,853,261)	(2,531,420)	(956,154)	(744,176)	429,276	1,823,598	4,161,113	7,271,767	10,545,907	14,046,671	17,018,497	19,183,506	(3,853,261)
a. Deferred True-Up from January to December 2020 (Order No. PSC-2020-0433-FOF-EI)	4,237,191	4,237,191	4,237,191	4,237,191	4,237,191	4,237,191	4,237,191	4,237,191	4,237,191	4,237,191	4,237,191	4,237,191	4,237,191
8. True-Up Collected/(Refunded) (see Line 2)	321,105	321,105	321,105	321,105	321,105	321,105	321,105	321,105	321,105	321,105	321,105	321,106	3,853,261
9. End of Period Total True-Up (Lines 5+6+7+7a+8)	1,705,771	3,281,037	3,493,015	4,666,467	6,060,789	8,398,304	11,508,958	14,783,098	18,283,862	21,255,688	23,420,697	25,396,024	25,396,024
10. Adjustment to Period True-Up Including Interest	0	0	0	0	0	0	0	0	0	0	0	0	0
11. End of Period Total True-Up (Lines 9 + 10)	$1,705,771	$3,281,037	$3,493,015	$4,666,467	$6,060,789	$8,398,304	$11,508,958	$14,783,098	$18,283,862	$21,255,688	$23,420,697	$25,396,024	$25,396,024

Form 42 - 3E

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Interest Provision
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Beginning True-Up Amount (Form 42-2A, Line 7 + 7a + 10)	$383,930	$1,705,771	$3,281,037	$3,493,015	$4,666,467	$6,060,789	$8,398,304	$11,508,958	$14,783,098	$18,283,862	$21,255,688	$23,420,697	
2.	Ending True-Up Amount Before Interest	1,705,677	3,280,813	3,492,744	4,666,141	6,060,521	8,397,943	11,507,067	14,778,892	18,278,572	21,249,363	23,413,550	25,388,215	
3.	Total of Beginning & Ending True-Up (Lines 1 + 2)	2,089,607	4,986,584	6,773,781	8,159,156	10,726,988	14,458,732	19,905,371	26,287,850	33,061,670	39,533,225	44,669,238	48,808,912	
4.	Average True-Up Amount (Line 3 x 1/2)	1,044,804	2,493,292	3,386,891	4,079,578	5,363,494	7,229,366	9,952,686	13,143,925	16,530,835	19,766,613	22,334,619	24,404,456	
5.	Interest Rate (First Day of Reporting Business Month)	0.10%	0.12%	0.09%	0.11%	0.07%	0.04%	0.08%	0.38%	0.38%	0.38%	0.38%	0.38%	
6.	Interest Rate (First Day of Subsequent Business Month)	0.12%	0.09%	0.11%	0.07%	0.04%	0.08%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	
7.	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	0.22%	0.21%	0.20%	0.18%	0.11%	0.12%	0.46%	0.76%	0.76%	0.76%	0.76%	0.76%	
8.	Average Interest Rate (Line 7 x 1/2)	0.110%	0.105%	0.100%	0.090%	0.055%	0.060%	0.230%	0.380%	0.380%	0.380%	0.380%	0.380%	
9.	Monthly Average Interest Rate (Line 8 x 1/12)	0.009%	0.009%	0.008%	0.008%	0.005%	0.005%	0.019%	0.032%	0.032%	0.032%	0.032%	0.032%	
10.	Interest Provision for the Month (Line 4 x Line 9)	$94	$224	$271	$326	$268	$361	$1,891	$4,206	$5,290	$6,325	$7,147	$7,809	$34,212

Form 42 - 4E

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Variance Report of O & M Activities
(In Dollars)

Line		(1) Actual / Estimated	(2) Original Projection	(3) Variance Amount	(4) Variance Percent
1.	Description of O&M Activities				
	a. Big Bend Unit 3 Flue Gas Desulfurization Integration	0	0	0	0.0%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0.0%
	c. SO_2 Emissions Allowances	41	15	26	170.2%
	d. Big Bend Units 1 & 2 FGD	8,966	0	8,966	100.0%
	e. Big Bend PM Minimization and Monitoring	218,747	252,000	(33,253)	-13.2%
	f. Big Bend NO_x Emissions Reduction	2,950	2,028	922	45.5%
	g. NPDES Annual Surveillance Fees	34,500	23,500	11,000	46.8%
	h. Gannon Thermal Discharge Study	0	0	0	0.0%
	i. Polk NO_x Emissions Reduction	595	0	595	100.0%
	j. Bayside SCR Consumables	139,173	119,000	20,173	17.0%
	k. Big Bend Unit 4 SOFA	0	0	0	0.0%
	l. Big Bend Unit 1 Pre-SCR	0	0	0	0.0%
	m. Big Bend Unit 2 Pre-SCR	0	0	0	0.0%
	n. Big Bend Unit 3 Pre-SCR	0	0	0	0.0%
	o. Clean Water Act Section 316(b) Phase II Study	6,020	45,000	(38,980)	-86.6%
	p. Arsenic Groundwater Standard Program	0	36,000	(36,000)	-100.0%
	q. Big Bend 1 SCR	0	0	0	0.0%
	r. Big Bend 2 SCR	106,340	122,020	(15,680)	-12.9%
	s. Big Bend 3 SCR	542,672	524,097	18,575	3.5%
	t. Big Bend 4 SCR	893,479	1,077,230	(183,752)	-17.1%
	u. Mercury Air Toxics Standards	5,494	3,000	2,494	83.1%
	v. Greenhouse Gas Reduction Program	93,149	93,528	(379)	-0.4%
	w. Big Bend Gypsum Storage Facility	621,996	1,177,899	(555,903)	-47.2%
	x. Coal Combustion Residuals (CCR) Rule	763,222	0	763,222	100.0%
	y. Big Bend ELG Compliance	0	4,800	(4,800)	-100.0%
	z. CCR Rule - Phase II	5,813,349	0	5,813,349	100.0%
	aa. Big Bend Unit 1 Sec. 316(b) Impingement Mortality	0	0	0	0.0%
2.	Total Investment Projects - Recoverable Costs	$9,250,693	$3,480,118	$5,770,575	165.8%
3.	Recoverable Costs Allocated to Energy	$9,210,173	$3,375,618	$5,834,555	172.8%
4.	Recoverable Costs Allocated to Demand	$40,520	$104,500	($63,980)	-61.2%

Notes:
Column (1) is the End of Period Totals on Form 42-5E.
Column (2) is the approved projected amount in accordance with FPSC Order No. PSC-2020-0433-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

O&M Activities
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	Description of O&M Activities															
a.	Big Bend Unit 3 Flue Gas Desulfurization Integration	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0
b.	Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0	0	0	0	0	0	0	0	0	0		0
c.	SO_2 Emissions Allowances	(6)	11	9	(11)	5	14	(5)	7	7	(5)	7	7	41		41
d.	Big Bend Units 1 & 2 FGD	176	188	945	2,398	464	794	1,000	1,000	1,000	1,000	0	0	8,966		8,966
e.	Big Bend PM Minimization and Monitoring	17,045	4,150	44,199	(2,952)	26,981	16,900	18,500	18,500	18,500	18,500	18,500	19,923	218,747		218,747
f.	Big Bend NO_x Emissions Reduction	0	0	2,950	0	0	0	0	0	0	0	0	0	2,950		2,950
g.	NPDES Annual Surveillance Fees	0	34,500	0	0	0	0	0	0	0	0	0	0	34,500	$34,500	
h.	Gannon Thermal Discharge Study	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
i.	Polk NO_x Emissions Reduction	519	76	0	0	0	0	0	0	0	0	0	0	595		595
j.	Bayside SCR and Ammonia	11,422	14,882	17,237	15,349	16,033	3,250	12,000	12,000	11,000	10,000	8,000	8,000	139,173		139,173
k.	Big Bend Unit 4 SOFA	0	0	0	0	0	0	0	0	0	0	0	0	0		0
l.	Big Bend Unit 1 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
m.	Big Bend Unit 2 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
n.	Big Bend Unit 3 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
o.	Clean Water Act Section 316(b) Phase II Study	(1,368)	1,006	200	400	218	0	0	0	0	0	2,500	3,065	6,020	6,020	
p.	Arsenic Groundwater Standard Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
q.	Big Bend 1 SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
r.	Big Bend 2 SCR	15,753	9,249	6,312	91	78	417	14,216	13,361	14,964	31,900	0	0	106,340		106,340
s.	Big Bend 3 SCR	40,305	41,595	16,619	5,616	15,451	90,744	39,638	34,892	34,495	37,843	110,731	74,745	542,672		542,672
t.	Big Bend 4 SCR	99,349	89,285	88,800	42,513	61,380	176,163	75,768	77,978	76,773	54,653	15,000	35,817	893,479		893,479
u.	Mercury Air Toxics Standards	0	0	5,539	0	(45)	0	0	0	0	0	0	0	5,494		5,494
v.	Greenhouse Gas Reduction Program	0	0	0	0	93,149	0	0	0	0	0	0	0	93,149		93,149
w.	Big Bend Gypsum Storage Facility (East 40)	7,164	14,525	1,005	13,307	10,773	20,080	92,524	92,524	92,524	92,524	92,524	92,524	621,996		621,996
x.	Coal Combustion Residuals (CCR) Rule - Phase I	516,830	(392,842)	483,934	2,758	0	152,542	0	0	0	0	0	0	763,222		763,222
y.	Big Bend ELG Compliance	0	0	0	0	0	0	0	0	0	0	0	0	0		0
z.	Coal Combustion Residuals (CCR) Rule - Phase II	540,408	752,471	1,239,623	1,178,542	1,216,291	686,013	200,000	0	0	0	0	0	5,813,349		5,813,349
aa.	Big Bend Unit 1 Sec. 316(b) Impingement Mortality	0	0	0	0	0	0	0	0	0	0	0	0	0		0
2.	Total of O&M Activities	1,247,596	569,096	1,907,372	1,258,012	1,440,778	1,146,917	453,640	250,262	249,262	246,415	247,262	234,080	9,250,693	$40,520	$9,210,173
3.	Recoverable Costs Allocated to Energy	1,248,964	533,590	1,907,172	1,257,612	1,440,560	1,146,917	453,640	250,262	249,262	246,415	244,762	231,015	9,210,173		
4.	Recoverable Costs Allocated to Demand	(1,368)	35,506	200	400	218	0	0	0	0	0	2,500	3,065	40,520		
5.	Retail Energy Jurisdictional Factor	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
6.	Retail Demand Jurisdictional Factor	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
7.	Jurisdictional Energy Recoverable Costs (A)	1,248,964	533,590	1,907,172	1,257,612	1,440,560	1,146,917	453,640	250,262	249,262	246,415	244,762	231,015	9,210,172		
8.	Jurisdictional Demand Recoverable Costs (B)	(1,368)	35,506	200	400	218	0	0	0	0	0	2,500	3,065	40,521		
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$1,247,596	$569,096	$1,907,372	$1,258,012	$1,440,778	$1,146,917	$453,640	$250,262	249,262	246,415	$247,262	$234,080	$9,250,693		

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6

DOCKET NO. 20210007-EI
EXHIBIT NO. MAS-4, FORM 42-5E
DOCUMENT NO. 2, PAGE 1 OF 1
FILED: 10/01/2021

Form 42 - 6E

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Variance Report of Capital Investment Projects - Recoverable Costs
(In Dollars)

Line			(1) Actual / Estimated	(2) Original Projection	(3) Variance Amount	(4) Variance Percent
1.		Description of Investment Projects				
	a.	Big Bend Unit 3 Flue Gas Desulfurization Integration	$895,982	$906,095	($10,113)	-1.1%
	b.	Big Bend Units 1 & 2 Flue Gas Conditioning	192,813	193,042	(229)	-0.1%
	c.	Big Bend Unit 4 Continuous Emissions Monitors	45,275	45,598	(323)	-0.7%
	d.	Big Bend Fuel Oil Tank # 1 Upgrade	63,858	63,896	(38)	-0.1%
	e.	Big Bend Fuel Oil Tank # 2 Upgrade	105,023	105,098	(75)	-0.1%
	f.	Big Bend Unit 1 Classifier Replacement	68,898	69,201	(303)	-0.4%
	g.	Big Bend Unit 2 Classifier Replacement	50,229	50,482	(253)	-0.5%
	h.	Big Bend Section 114 Mercury Testing Platform	7,877	7,958	(81)	-1.0%
	i.	Big Bend Units 1 & 2 FGD	1,614,517	5,440,931	(3,826,414)	-70.3%
	j.	Big Bend FGD Optimization and Utilization	1,490,341	1,507,233	(16,892)	-1.1%
	k.	Big Bend NO_x Emissions Reduction	480,621	487,214	(6,593)	-1.4%
	l.	Big Bend PM Minimization and Monitoring	1,667,447	1,684,675	(17,228)	-1.0%
	m.	Polk NO_x Emissions Reduction	102,518	103,428	(910)	-0.9%
	n.	Big Bend Unit 4 SOFA	183,522	185,486	(1,964)	-1.1%
	o.	Big Bend Unit 1 Pre-SCR	124,162	125,229	(1,067)	-0.9%
	p.	Big Bend Unit 2 Pre-SCR	119,051	120,162	(1,111)	-0.9%
	q.	Big Bend Unit 3 Pre-SCR	214,540	216,730	(2,190)	-1.0%
	r.	Big Bend Unit 1 SCR	0	7,165,809	(7,165,809)	-100.0%
	s.	Big Bend Unit 2 SCR	0	7,893,828	(7,893,828)	-100.0%
	t.	Big Bend Unit 3 SCR	0	6,429,857	(6,429,857)	-100.0%
	u.	Big Bend Unit 4 SCR	5,128,650	5,199,976	(71,326)	-1.4%
	v.	Big Bend FGD System Reliability	1,987,999	2,013,174	(25,175)	-1.3%
	w.	Mercury Air Toxics Standards	773,921	783,036	(9,115)	-1.2%
	x.	$S0_2$ Emissions Allowances	(2,652)	(2,688)	36	-1.3%
	y.	Big Bend Gypsum Storage Facility	1,966,371	1,991,084	(24,713)	-1.2%
	z.	Big Bend Coal Combustion Residual Rule (CCR Rule)	321,517	362,933	(41,416)	-11.4%
	aa.	Coal Combustion Residuals (CCR-Phase II)	126,670	328,169	(201,499)	-61.4%
	ab.	Big Bend ELG Compliance	433,565	782,650	(349,085)	-44.6%
	ac.	Big Bend Unit 1 Sec. 316(b) Impingement Mortality	477,788	452,502	25,286	5.6%
2.		Total Investment Projects - Recoverable Costs	$18,640,503	$44,712,788	($26,072,285)	-58.3%
3.		Recoverable Costs Allocated to Energy	$17,112,082	$42,617,540	($25,505,458)	-59.8%
4.		Recoverable Costs Allocated to Demand	$1,528,421	$2,095,248	($566,827)	-27.1%

Notes:
Column (1) is the End of Period Totals on Form 42-7E.
Column (2) is the approved projected amount in accordance with FPSC Order No. PSC-2020-0433-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Form 42-7E

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line		Description (A)		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	a.	Big Bend Unit 3 Flue Gas Desulfurization Integration	1	$75,688	$75,501	$75,316	$75,129	$74,944	$74,758	$74,572	$74,387	$74,200	$74,015	$73,829	$73,643	$895,982		$895,982
	b.	Big Bend Units 1 and 2 Flue Gas Conditioning	2	17,747	17,644	17,540	17,436	17,332	17,228	17,124	17,019	16,915	16,811	12,278	7,739	192,813		192,813
	c.	Big Bend Unit 4 Continuous Emissions Monitors	3	3,855	3,840	3,825	3,810	3,795	3,780	3,766	3,751	3,736	3,720	3,706	3,691	45,275		45,275
	d.	Big Bend Fuel Oil Tank # 1 Upgrade	4	5,503	5,470	5,437	5,404	5,371	5,338	5,305	5,272	5,239	5,206	5,173	5,140	63,858	$63,858	
	e.	Big Bend Fuel Oil Tank # 2 Upgrade	5	9,051	8,996	8,941	8,888	8,833	8,779	8,724	8,670	8,616	8,562	8,507	8,456	105,023	105,023	
	f.	Big Bend Unit 1 Classifier Replacement	6	5,897	5,869	5,840	5,812	5,784	5,756	5,727	5,699	5,671	5,643	5,614	5,586	68,898		68,898
	g.	Big Bend Unit 2 Classifier Replacement	7	4,293	4,274	4,255	4,234	4,215	4,195	4,176	4,157	4,137	4,118	4,097	4,078	50,229		50,229
	h.	Big Bend Section 114 Mercury Testing Platform	8	667	665	663	661	659	658	655	654	651	650	648	646	7,877		7,877
	i.	Big Bend Units 1 & 2 FGD	9	137,318	136,814	136,309	135,805	135,300	134,796	134,291	133,786	133,281	132,777	132,272	131,768	1,614,517		1,614,517
	j.	Big Bend FGD Optimization and Utilization	10	125,883	125,577	125,270	124,963	124,656	124,348	124,041	123,734	123,428	123,121	122,814	122,506	1,490,341		1,490,341
	k.	Big Bend NO_x Emissions Reduction	11	40,413	40,347	40,282	40,216	40,150	40,085	40,019	39,953	39,888	39,822	39,756	39,690	480,621		480,621
	l.	Big Bend PM Minimization and Monitoring	12	141,111	140,719	140,327	139,935	139,542	139,150	138,758	138,366	137,973	137,581	137,189	136,796	1,667,447		1,667,447
	m.	Polk NO_x Emissions Reduction	13	8,700	8,672	8,643	8,615	8,586	8,557	8,529	8,500	8,472	8,443	8,415	8,386	102,518		102,518
	n.	Big Bend Unit 4 SOFA	14	15,521	15,479	15,438	15,396	15,356	15,314	15,273	15,231	15,191	15,149	15,108	15,066	183,522		183,522
	o.	Big Bend Unit 1 Pre-SCR	15	10,542	10,506	10,471	10,435	10,400	10,364	10,329	10,293	10,259	10,223	10,188	10,152	124,162		124,162
	p.	Big Bend Unit 2 Pre-SCR	16	10,093	10,063	10,031	9,999	9,968	9,937	9,905	9,874	9,842	9,811	9,780	9,748	119,051		119,051
	q.	Big Bend Unit 3 Pre-SCR	17	18,160	18,109	18,058	18,006	17,955	17,904	17,852	17,802	17,751	17,699	17,648	17,596	214,540		214,540
	r.	Big Bend Unit 1 SCR	18	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	s.	Big Bend Unit 2 SCR	19	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	t.	Big Bend Unit 3 SCR	20	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	u.	Big Bend Unit 4 SCR	21	433,038	431,798	430,557	429,322	428,102	426,897	425,724	424,593	424,419	425,026	424,959	424,215	5,128,650		5,128,650
	v.	Big Bend FGD System Reliability	22	167,495	167,162	166,830	166,497	166,166	165,833	165,500	165,168	164,835	164,503	164,171	163,839	1,987,999		1,987,999
	w.	Mercury Air Toxics Standards	23	65,268	65,124	64,981	64,836	64,693	64,549	64,406	64,301	64,157	64,013	63,868	63,725	773,921		773,921
	x.	SO_2 Emissions Allowances (B)	24	(221)	(221)	(221)	(221)	(221)	(221)	(221)	(221)	(221)	(221)	(221)	(221)	(2,652)		(2,652)
	y.	Big Bend Gypsum Storage Facility	25	165,702	165,368	165,034	164,700	164,366	164,032	163,697	163,363	163,029	162,694	162,360	162,026	1,966,371		1,966,371
	z.	Big Bend Coal Combustion Residual Rule (CCR Rule)	26	21,027	24,096	25,283	25,962	26,050	26,201	26,557	26,845	26,830	26,815	32,953	32,898	321,517	321,517	
	aa.	Coal Combustion Residuals (CCR-Phase II)	27	7,495	7,660	7,791	7,817	7,856	7,904	8,761	10,445	12,121	12,946	17,953	17,921	126,670	126,670	
	ab.	Big Bend ELG Compliance	28	16,695	17,592	18,913	19,805	21,179	24,480	30,255	36,201	41,889	55,463	70,600	80,493	433,565	433,565	
	ac.	Big Bend Unit 1 Impingement Mortality - 316(b)	29	8,424	10,832	17,915	25,059	27,022	31,091	36,969	43,102	53,009	66,355	76,548	81,462	477,788	477,788	
2.		Total Investment Projects - Recoverable Costs		1,515,365	1,517,956	1,523,729	1,528,521	1,528,059	1,531,713	1,540,694	1,550,945	1,565,318	1,590,945	1,620,213	1,627,045	18,640,503	$1,528,421	$17,112,082
3.		Recoverable Costs Allocated to Energy		1,447,170	1,443,310	1,439,449	1,435,586	1,431,748	1,427,920	1,424,123	1,420,410	1,417,614	1,415,598	1,408,479	1,400,675	17,112,082		17,112,082
4.		Recoverable Costs Allocated to Demand		68,195	74,646	84,280	92,935	96,311	103,793	116,571	130,535	147,704	175,347	211,734	226,370	1,528,421	1,528,421	
5.		Retail Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
6.		Retail Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
7.		Jurisdictional Energy Recoverable Costs (C)		1,447,170	1,443,310	1,439,449	1,435,586	1,431,748	1,427,920	1,424,123	1,420,410	1,417,614	1,415,598	1,408,479	1,400,675	17,112,082		
8.		Jurisdictional Demand Recoverable Costs (D)		68,195	74,646	84,280	92,935	96,311	103,793	116,571	130,535	147,704	175,347	211,734	226,370	1,528,421		
9.		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)		$1,515,365	$1,517,956	$1,523,729	$1,528,521	$1,528,059	$1,531,713	$1,540,694	$1,550,945	$1,565,318	$1,590,945	$1,620,213	$1,627,045	$18,640,503		

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-8E, Line 9
(B) Project's Total Return Component on Form 42-8E, Line 6
(C) Line 3 x Line 5
(D) Line 4 x Line 6

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Flue Gas Desulfurization Integration
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	
3.	Less: Accumulated Depreciation	(6,478,449)	(6,507,287)	(6,536,125)	(6,564,963)	(6,593,801)	(6,622,639)	(6,651,477)	(6,680,315)	(6,709,153)	(6,737,991)	(6,766,829)	(6,795,667)	(6,824,505)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$7,284,814	$7,255,976	$7,227,138	$7,198,300	$7,169,462	$7,140,624	$7,111,786	$7,082,948	$7,054,110	$7,025,272	$6,996,434	$6,967,596	$6,938,758	
6.	Average Net Investment		7,270,395	7,241,557	7,212,719	7,183,881	7,155,043	7,126,205	7,097,367	7,068,529	7,039,691	7,010,853	6,982,015	6,953,177	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$36,905	$36,758	$36,612	$36,465	$36,319	$36,173	$36,026	$35,880	$35,733	$35,587	$35,441	$35,294	$433,193
	b. Debt Component Grossed Up For Taxes (C)		9,945	9,905	9,866	9,826	9,787	9,747	9,708	9,669	9,629	9,590	9,550	9,511	116,733
8.	Investment Expenses														
	a. Depreciation (D)		28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	346,056
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		75,688	75,501	75,316	75,129	74,944	74,758	74,572	74,387	74,200	74,015	73,829	73,643	895,982
	a. Recoverable Costs Allocated to Energy		75,688	75,501	75,316	75,129	74,944	74,758	74,572	74,387	74,200	74,015	73,829	73,643	895,982
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		75,688	75,501	75,316	75,129	74,944	74,758	74,572	74,387	74,200	74,015	73,829	73,643	895,982
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$75,688	$75,501	$75,316	$75,129	$74,944	$74,758	$74,572	$74,387	$74,200	$74,015	$73,829	$73,643	$895,982

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.45 ($13,435,775), 315.45 ($327,307), and 312.40 ($182).
(B) Line 6 x 6.0912% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 2.5%, 3.1%, and 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 Flue Gas Conditioning
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	
3.	Less: Accumulated Depreciation	(4,760,354)	(4,776,495)	(4,792,636)	(4,808,777)	(4,824,918)	(4,841,059)	(4,857,200)	(4,873,341)	(4,889,482)	(4,905,623)	(4,921,764)	(4,933,462)	(4,940,682)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$257,380	$241,239	$225,098	$208,957	$192,816	$176,675	$160,534	$144,393	$128,252	$112,111	$95,970	$84,272	$77,052	
6.	Average Net Investment		249,310	233,169	217,028	200,887	184,746	168,605	152,464	136,323	120,182	104,041	90,121	80,662	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,265	$1,184	$1,102	$1,020	$938	$856	$774	$692	$610	$528	$457	$409	$9,835
	b. Debt Component Grossed Up For Taxes (C)		341	319	297	275	253	231	209	186	164	142	123	110	2,650
8.	Investment Expenses														
	a. Depreciation (D)		16,141	16,141	16,141	16,141	16,141	16,141	16,141	16,141	16,141	16,141	11,698	7,220	180,328
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		17,747	17,644	17,540	17,436	17,332	17,228	17,124	17,019	16,915	16,811	12,278	7,739	192,813
	a. Recoverable Costs Allocated to Energy		17,747	17,644	17,540	17,436	17,332	17,228	17,124	17,019	16,915	16,811	12,278	7,739	192,813
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		17,747	17,644	17,540	17,436	17,332	17,228	17,124	17,019	16,915	16,811	12,278	7,739	192,813
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$17,747	$17,644	$17,540	$17,436	$17,332	$17,228	$17,124	$17,019	$16,915	$16,811	$12,278	$7,739	$192,813

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($2,676,217) and 312.42 ($2,341,517).
(B) Line 6 x 6.0912% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 4.0% and 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 Continuous Emissions Monitors
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	
3.	Less: Accumulated Depreciation	(625,325)	(627,635)	(629,945)	(632,255)	(634,565)	(636,875)	(639,185)	(641,495)	(643,805)	(646,115)	(648,425)	(650,735)	(653,045)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$240,886	$238,576	$236,266	$233,956	$231,646	$229,336	$227,026	$224,716	$222,406	$220,096	$217,786	$215,476	$213,166	
6.	Average Net Investment		239,731	237,421	235,111	232,801	230,491	228,181	225,871	223,561	221,251	218,941	216,631	214,321	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,217	$1,205	$1,193	$1,182	$1,170	$1,158	$1,147	$1,135	$1,123	$1,111	$1,100	$1,088	$13,829
	b. Debt Component Grossed Up For Taxes (C)		328	325	322	318	315	312	309	306	303	299	296	293	3,726
8.	Investment Expenses														
	a. Depreciation (D)		2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	27,720
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		3,855	3,840	3,825	3,810	3,795	3,780	3,766	3,751	3,736	3,720	3,706	3,691	45,275
	a. Recoverable Costs Allocated to Energy		3,855	3,840	3,825	3,810	3,795	3,780	3,766	3,751	3,736	3,720	3,706	3,691	45,275
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		3,855	3,840	3,825	3,810	3,795	3,780	3,766	3,751	3,736	3,720	3,706	3,691	45,275
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$3,855	$3,840	$3,825	$3,810	$3,795	$3,780	$3,766	$3,751	$3,736	$3,720	$3,706	$3,691	$45,275

Notes:
(A) Applicable depreciable base for Big Bend; account 315.44
(B) Line 6 x 6.0912% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 3.2%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 1 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	
3.	Less: Accumulated Depreciation	(436,102)	(441,225)	(446,348)	(451,471)	(456,594)	(461,717)	(466,840)	(471,963)	(477,086)	(482,209)	(487,332)	(492,455)	(497,578)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$61,476	$56,353	$51,230	$46,107	$40,984	$35,861	$30,738	$25,615	$20,492	$15,369	$10,246	$5,123	$0	
6.	Average Net Investment		58,915	53,792	48,669	43,546	38,423	33,300	28,177	23,054	17,931	12,808	7,685	2,562	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$299	$273	$247	$221	$195	$169	$143	$117	$91	$65	$39	$13	$1,872
	b. Debt Component Grossed Up For Taxes (C)		81	74	67	60	53	46	39	32	25	18	11	4	510
8.	Investment Expenses														
	a. Depreciation (D)		5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	61,476
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		5,503	5,470	5,437	5,404	5,371	5,338	5,305	5,272	5,239	5,206	5,173	5,140	63,858
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		5,503	5,470	5,437	5,404	5,371	5,338	5,305	5,272	5,239	5,206	5,173	5,140	63,858
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		5,503	5,470	5,437	5,404	5,371	5,338	5,305	5,272	5,239	5,206	5,173	5,140	63,858
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$5,503	$5,470	$5,437	$5,404	$5,371	$5,338	$5,305	$5,272	$5,239	$5,206	$5,173	$5,140	$63,858

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 6.0912% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 12.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 2 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	
3.	Less: Accumulated Depreciation	(717,286)	(725,712)	(734,138)	(742,564)	(750,990)	(759,416)	(767,842)	(776,268)	(784,694)	(793,120)	(801,546)	(809,972)	(818,401)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$101,115	$92,689	$84,263	$75,837	$67,411	$58,985	$50,559	$42,133	$33,707	$25,281	$16,855	$8,429	$0	
6.	Average Net Investment		96,902	88,476	80,050	71,624	63,198	54,772	46,346	37,920	29,494	21,068	12,642	4,215	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$492	$449	$406	$364	$321	$278	$235	$192	$150	$107	$64	$21	$3,079
	b. Debt Component Grossed Up For Taxes (C)		133	121	109	98	86	75	63	52	40	29	17	6	829
8.	Investment Expenses														
	a. Depreciation (D)		8,426	8,426	8,426	8,426	8,426	8,426	8,426	8,426	8,426	8,426	8,426	8,429	101,115
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		9,051	8,996	8,941	8,888	8,833	8,779	8,724	8,670	8,616	8,562	8,507	8,456	105,023
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		9,051	8,996	8,941	8,888	8,833	8,779	8,724	8,670	8,616	8,562	8,507	8,456	105,023
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		9,051	8,996	8,941	8,888	8,833	8,779	8,724	8,670	8,616	8,562	8,507	8,456	105,023
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$9,051	$8,996	$8,941	$8,888	$8,833	$8,779	$8,724	$8,670	$8,616	$8,562	$8,507	$8,456	$105,023

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 6.0912% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 12.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	
3.	Less: Accumulated Depreciation	(1,079,816)	(1,084,204)	(1,088,592)	(1,092,980)	(1,097,368)	(1,101,756)	(1,106,144)	(1,110,532)	(1,114,920)	(1,119,308)	(1,123,696)	(1,128,084)	(1,132,472)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$236,441	$232,053	$227,665	$223,277	$218,889	$214,501	$210,113	$205,725	$201,337	$196,949	$192,561	$188,173	$183,785	
6.	Average Net Investment		234,247	229,859	225,471	221,083	216,695	212,307	207,919	203,531	199,143	194,755	190,367	185,979	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,189	$1,167	$1,144	$1,122	$1,100	$1,078	$1,055	$1,033	$1,011	$989	$966	$944	$12,798
	b. Debt Component Grossed Up For Taxes (C)		320	314	308	302	296	290	284	278	272	266	260	254	3,444
8.	Investment Expenses														
	a. Depreciation (D)		4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	52,656
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		5,897	5,869	5,840	5,812	5,784	5,756	5,727	5,699	5,671	5,643	5,614	5,586	68,898
	a. Recoverable Costs Allocated to Energy		5,897	5,869	5,840	5,812	5,784	5,756	5,727	5,699	5,671	5,643	5,614	5,586	68,898
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		5,897	5,869	5,840	5,812	5,784	5,756	5,727	5,699	5,671	5,643	5,614	5,586	68,898
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$5,897	$5,869	$5,840	$5,812	$5,784	$5,756	$5,727	$5,699	$5,671	$5,643	$5,614	$5,586	$68,898

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 6.0912% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 4.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	
3.	Less: Accumulated Depreciation	(788,166)	(791,202)	(794,238)	(797,274)	(800,310)	(803,346)	(806,382)	(809,418)	(812,454)	(815,490)	(818,526)	(821,562)	(824,598)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$196,628	$193,592	$190,556	$187,520	$184,484	$181,448	$178,412	$175,376	$172,340	$169,304	$166,268	$163,232	$160,196	
6.	Average Net Investment		195,110	192,074	189,038	186,002	182,966	179,930	176,894	173,858	170,822	167,786	164,750	161,714	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$990	$975	$960	$944	$929	$913	$898	$883	$867	$852	$836	$821	$10,868
	b. Debt Component Grossed Up For Taxes (C)		267	263	259	254	250	246	242	238	234	230	225	221	2,929
8.	Investment Expenses														
	a. Depreciation (D)		3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	36,432
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		4,293	4,274	4,255	4,234	4,215	4,195	4,176	4,157	4,137	4,118	4,097	4,078	50,229
	a. Recoverable Costs Allocated to Energy		4,293	4,274	4,255	4,234	4,215	4,195	4,176	4,157	4,137	4,118	4,097	4,078	50,229
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		4,293	4,274	4,255	4,234	4,215	4,195	4,176	4,157	4,137	4,118	4,097	4,078	50,229
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
15	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$4,293	$4,274	$4,255	$4,234	$4,215	$4,195	$4,176	$4,157	$4,137	$4,118	$4,097	$4,078	$50,229

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 6.0912% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Section 114 Mercury Testing Platform
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	
3.	Less: Accumulated Depreciation	(62,419)	(62,711)	(63,003)	(63,295)	(63,587)	(63,879)	(64,171)	(64,463)	(64,755)	(65,047)	(65,339)	(65,631)	(65,923)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$58,318	$58,026	$57,734	$57,442	$57,150	$56,858	$56,566	$56,274	$55,982	$55,690	$55,398	$55,106	$54,814	
6.	Average Net Investment		58,172	57,880	57,588	57,296	57,004	56,712	56,420	56,128	55,836	55,544	55,252	54,960	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$295	$294	$292	$291	$289	$288	$286	$285	$283	$282	$280	$279	$3,444
	b. Debt Component Grossed Up For Taxes (C)		80	79	79	78	78	78	77	77	76	76	76	75	929
8.	Investment Expenses														
	a. Depreciation (D)		292	292	292	292	292	292	292	292	292	292	292	292	3,504
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		667	665	663	661	659	658	655	654	651	650	648	646	7,877
	a. Recoverable Costs Allocated to Energy		667	665	663	661	659	658	655	654	651	650	648	646	7,877
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		667	665	663	661	659	658	655	654	651	650	648	646	7,877
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$667	$665	$663	$661	$659	$658	$655	$654	$651	$650	$648	$646	$7,877

Notes:
(A) Applicable depreciable base for Big Bend; account 311.40
(B) Line 6 x 6.0912% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 2.9%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

20210007-EI Staff Hearing Exhibits 00203

DOCKET NO. 20210007-EI
EXHIBIT NO. MAS-4, FORM 42-8E
DOCUMENT NO. 2, PAGE 9 OF 29
FILED: 10/01/2021

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 FGD
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$28,490,542	$28,490,542	$28,490,542	$28,490,542	$28,490,542	$28,490,542	$28,490,542	$28,490,542	$28,490,542	$28,490,542	$28,490,542	$28,490,542	$28,490,542	
3.	Less: Accumulated Depreciation	(19,292,974)	(19,371,277)	(19,449,580)	(19,527,883)	(19,606,186)	(19,684,489)	(19,762,792)	(19,841,095)	(19,919,398)	(19,997,701)	(20,076,004)	(20,154,307)	(20,232,610)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$9,197,568	$9,119,265	$9,040,962	$8,962,659	$8,884,356	$8,806,053	$8,727,750	$8,649,447	$8,571,144	$8,492,841	$8,414,538	$8,336,235	$8,257,932	
6.	Average Net Investment		9,158,417	9,080,114	9,001,811	8,923,508	8,845,205	8,766,902	8,688,599	8,610,296	8,531,993	8,453,690	8,375,387	8,297,084	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$46,488	$46,091	$45,693	$45,296	$44,898	$44,501	$44,103	$43,706	$43,308	$42,911	$42,513	$42,116	$531,624
	b. Debt Component Grossed Up For Taxes (C)		12,527	12,420	12,313	12,206	12,099	11,992	11,885	11,777	11,670	11,563	11,456	11,349	143,257
8.	Investment Expenses														
	a. Depreciation (D)		78,303	78,303	78,303	78,303	78,303	78,303	78,303	78,303	78,303	78,303	78,303	78,303	939,636
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		137,318	136,814	136,309	135,805	135,300	134,796	134,291	133,786	133,281	132,777	132,272	131,768	1,614,517
	a. Recoverable Costs Allocated to Energy		137,318	136,814	136,309	135,805	135,300	134,796	134,291	133,786	133,281	132,777	132,272	131,768	1,614,517
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		137,318	136,814	136,309	135,805	135,300	134,796	134,291	133,786	133,281	132,777	132,272	131,768	1,614,517
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$137,318	$136,814	$136,309	$135,805	$135,300	$134,796	$134,291	$133,786	$133,281	$132,777	$132,272	$131,768	$1,614,517

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.46 ($28,341,531), and 315.46 ($7,043).
(B) Line 6 x 6.0912% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 3.3%, and 3.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD Optimization and Utilization
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	
3.	Less: Accumulated Depreciation	(10,488,770)	(10,536,417)	(10,584,064)	(10,631,711)	(10,679,358)	(10,727,005)	(10,774,652)	(10,822,299)	(10,869,946)	(10,917,593)	(10,965,240)	(11,012,887)	(11,060,534)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$12,165,159	$12,117,512	$12,069,865	$12,022,218	$11,974,571	$11,926,924	$11,879,277	$11,831,630	$11,783,983	$11,736,336	$11,688,689	$11,641,042	$11,593,395	
6.	Average Net Investment		12,141,336	12,093,689	12,046,042	11,998,395	11,950,748	11,903,101	11,855,454	11,807,807	11,760,160	11,712,513	11,664,866	11,617,219	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$61,629	$61,388	$61,146	$60,904	$60,662	$60,420	$60,178	$59,936	$59,695	$59,453	$59,211	$58,969	$723,591
	b. Debt Component Grossed Up For Taxes (C)		16,607	16,542	16,477	16,412	16,347	16,281	16,216	16,151	16,086	16,021	15,956	15,890	194,986
8.	Investment Expenses														
	a. Depreciation (D)		47,647	47,647	47,647	47,647	47,647	47,647	47,647	47,647	47,647	47,647	47,647	47,647	571,764
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		125,883	125,577	125,270	124,963	124,656	124,348	124,041	123,734	123,428	123,121	122,814	122,506	1,490,341
	a. Recoverable Costs Allocated to Energy		125,883	125,577	125,270	124,963	124,656	124,348	124,041	123,734	123,428	123,121	122,814	122,506	1,490,341
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		125,883	125,577	125,270	124,963	124,656	124,348	124,041	123,734	123,428	123,121	122,814	122,506	1,490,341
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$125,883	$125,577	$125,270	$124,963	$124,656	$124,348	$124,041	$123,734	$123,428	$123,121	$122,814	$122,506	$1,490,341

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.45 ($21,855,886), 311.45 ($40,016), 316.40 ($71,401), 315.45 ($594,901), 312.42 ($1,637), and 312.40 ($90,088).
(B) Line 6 x 6.0912% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 2.5%, 2.0%, 4.2%, 3.1%, 3.7%, and 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Actual November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	
3.	Less: Accumulated Depreciation	1,505,355	1,495,171	1,484,987	1,474,803	1,464,619	1,454,435	1,444,251	1,434,067	1,423,883	1,413,699	1,403,515	1,393,331	1,383,147	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$4,696,207	$4,686,023	$4,675,839	$4,665,655	$4,655,471	$4,645,287	$4,635,103	$4,624,919	$4,614,735	$4,604,551	$4,594,367	$4,584,183	$4,573,999	
6.	Average Net Investment		4,691,115	4,680,931	4,670,747	4,660,563	4,650,379	4,640,195	4,630,011	4,619,827	4,609,643	4,599,459	4,589,275	4,579,091	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$23,812	$23,760	$23,709	$23,657	$23,605	$23,554	$23,502	$23,450	$23,399	$23,347	$23,295	$23,243	$282,333
	b. Debt Component Grossed Up For Taxes (C)		6,417	6,403	6,389	6,375	6,361	6,347	6,333	6,319	6,305	6,291	6,277	6,263	76,080
8.	Investment Expenses														
	a. Depreciation (D)		10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	122,208
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		40,413	40,347	40,282	40,216	40,150	40,085	40,019	39,953	39,888	39,822	39,756	39,690	480,621
	a. Recoverable Costs Allocated to Energy		40,413	40,347	40,282	40,216	40,150	40,085	40,019	39,953	39,888	39,822	39,756	39,690	480,621
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		40,413	40,347	40,282	40,216	40,150	40,085	40,019	39,953	39,888	39,822	39,756	39,690	480,621
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$40,413	$40,347	$40,282	$40,216	$40,150	$40,085	$40,019	$39,953	$39,888	$39,822	$39,756	$39,690	$480,621

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,675,171), 312.42 ($1,075,718), and 312.43 ($439,963).
(B) Line 6 x 6.0912% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 4.0%, 3.7%, and 3.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: PM Minimization and Monitoring
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	
3.	Less: Accumulated Depreciation	(7,275,250)	(7,336,122)	(7,396,994)	(7,457,866)	(7,518,738)	(7,579,610)	(7,640,482)	(7,701,354)	(7,762,226)	(7,823,098)	(7,883,970)	(7,944,842)	(8,005,714)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$12,482,500	$12,421,628	$12,360,756	$12,299,884	$12,239,012	$12,178,140	$12,117,268	$12,056,396	$11,995,524	$11,934,652	$11,873,780	$11,812,908	$11,752,036	
6.	Average Net Investment		12,452,064	12,391,192	12,330,320	12,269,448	12,208,576	12,147,704	12,086,832	12,025,960	11,965,088	11,904,216	11,843,344	11,782,472	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$63,207	$62,898	$62,589	$62,280	$61,971	$61,662	$61,353	$61,044	$60,735	$60,426	$60,117	$59,808	$738,090
	b. Debt Component Grossed Up For Taxes (C)		17,032	16,949	16,866	16,783	16,699	16,616	16,533	16,450	16,366	16,283	16,200	16,116	198,893
8.	Investment Expenses														
	a. Depreciation (D)		60,872	60,872	60,872	60,872	60,872	60,872	60,872	60,872	60,872	60,872	60,872	60,872	730,464
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		141,111	140,719	140,327	139,935	139,542	139,150	138,758	138,366	137,973	137,581	137,189	136,796	1,667,447
	a. Recoverable Costs Allocated to Energy		141,111	140,719	140,327	139,935	139,542	139,150	138,758	138,366	137,973	137,581	137,189	136,796	1,667,447
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		141,111	140,719	140,327	139,935	139,542	139,150	138,758	138,366	137,973	137,581	137,189	136,796	1,667,447
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$141,111	$140,719	$140,327	$139,935	$139,542	$139,150	$138,758	$138,366	$137,973	$137,581	$137,189	$136,796	$1,667,447

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($5,831,465), 312.42 ($5,153,072), 312.43 ($7,875,560), 315.41 ($17,504), 315.44 ($351,594), and 315.43 ($528,554).
(B) Line 6 x 6.0912% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 4.0%, 3.7%, 3.5%, 3.5%, 3.2%, and 3.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Polk NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	
3.	Less: Accumulated Depreciation	(895,674)	(900,098)	(904,522)	(908,946)	(913,370)	(917,794)	(922,218)	(926,642)	(931,066)	(935,490)	(939,914)	(944,338)	(948,762)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$665,799	$661,375	$656,951	$652,527	$648,103	$643,679	$639,255	$634,831	$630,407	$625,983	$621,559	$617,135	$612,711	
6.	Average Net Investment		663,587	659,163	654,739	650,315	645,891	641,467	637,043	632,619	628,195	623,771	619,347	614,923	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$3,368	$3,346	$3,323	$3,301	$3,279	$3,256	$3,234	$3,211	$3,189	$3,166	$3,144	$3,121	$38,938
	b. Debt Component Grossed Up For Taxes (C)		908	902	896	890	883	877	871	865	859	853	847	841	10,492
8.	Investment Expenses														
	a. Depreciation (D)		4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	53,088
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		8,700	8,672	8,643	8,615	8,586	8,557	8,529	8,500	8,472	8,443	8,415	8,386	102,518
	a. Recoverable Costs Allocated to Energy		8,700	8,672	8,643	8,615	8,586	8,557	8,529	8,500	8,472	8,443	8,415	8,386	102,518
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		8,700	8,672	8,643	8,615	8,586	8,557	8,529	8,500	8,472	8,443	8,415	8,386	102,518
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$8,700	$8,672	$8,643	$8,615	$8,586	$8,557	$8,529	$8,500	$8,472	$8,443	$8,415	$8,386	$102,518

Notes:
(A) Applicable depreciable base for Polk; account 342.81
(B) Line 6 x 6.0912% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SOFA
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	
3.	Less: Accumulated Depreciation	(1,139,726)	(1,146,123)	(1,152,520)	(1,158,917)	(1,165,314)	(1,171,711)	(1,178,108)	(1,184,505)	(1,190,902)	(1,197,299)	(1,203,696)	(1,210,093)	(1,216,490)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,419,004	$1,412,607	$1,406,210	$1,399,813	$1,393,416	$1,387,019	$1,380,622	$1,374,225	$1,367,828	$1,361,431	$1,355,034	$1,348,637	$1,342,240	
6.	Average Net Investment		1,415,806	1,409,409	1,403,012	1,396,615	1,390,218	1,383,821	1,377,424	1,371,027	1,364,630	1,358,233	1,351,836	1,345,439	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$7,187	$7,154	$7,122	$7,089	$7,057	$7,024	$6,992	$6,959	$6,927	$6,894	$6,862	$6,829	$84,096
	b. Debt Component Grossed Up For Taxes (C)		1,937	1,928	1,919	1,910	1,902	1,893	1,884	1,875	1,867	1,858	1,849	1,840	22,662
8.	Investment Expenses														
	a. Depreciation (D)		6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	76,764
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		15,521	15,479	15,438	15,396	15,356	15,314	15,273	15,231	15,191	15,149	15,108	15,066	183,522
	a. Recoverable Costs Allocated to Energy		15,521	15,479	15,438	15,396	15,356	15,314	15,273	15,231	15,191	15,149	15,108	15,066	183,522
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		15,521	15,479	15,438	15,396	15,356	15,314	15,273	15,231	15,191	15,149	15,108	15,066	183,522
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$15,521	$15,479	$15,438	$15,396	$15,356	$15,314	$15,273	$15,231	$15,191	$15,149	$15,108	$15,066	$183,522

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44
(B) Line 6 x 6.0912% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	
3.	Less: Accumulated Depreciation	(863,521)	(869,018)	(874,515)	(880,012)	(885,509)	(891,006)	(896,503)	(902,000)	(907,497)	(912,994)	(918,491)	(923,988)	(929,485)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$785,600	$780,103	$774,606	$769,109	$763,612	$758,115	$752,618	$747,121	$741,624	$736,127	$730,630	$725,133	$719,636	
6.	Average Net Investment		782,852	777,355	771,858	766,361	760,864	755,367	749,870	744,373	738,876	733,379	727,882	722,385	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$3,974	$3,946	$3,918	$3,890	$3,862	$3,834	$3,806	$3,778	$3,751	$3,723	$3,695	$3,667	$45,844
	b. Debt Component Grossed Up For Taxes (C)		1,071	1,063	1,056	1,048	1,041	1,033	1,026	1,018	1,011	1,003	996	988	12,354
8.	Investment Expenses														
	a. Depreciation (D)		5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	65,964
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		10,542	10,506	10,471	10,435	10,400	10,364	10,329	10,293	10,259	10,223	10,188	10,152	124,162
	a. Recoverable Costs Allocated to Energy		10,542	10,506	10,471	10,435	10,400	10,364	10,329	10,293	10,259	10,223	10,188	10,152	124,162
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		10,542	10,506	10,471	10,435	10,400	10,364	10,329	10,293	10,259	10,223	10,188	10,152	124,162
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$10,542	$10,506	$10,471	$10,435	$10,400	$10,364	$10,329	$10,293	$10,259	$10,223	$10,188	$10,152	$124,162

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 6.0912% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 4.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	
3.	Less: Accumulated Depreciation	(769,892)	(774,769)	(779,646)	(784,523)	(789,400)	(794,277)	(799,154)	(804,031)	(808,908)	(813,785)	(818,662)	(823,539)	(828,416)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$811,995	$807,118	$802,241	$797,364	$792,487	$787,610	$782,733	$777,856	$772,979	$768,102	$763,225	$758,348	$753,471	
6.	Average Net Investment		809,557	804,680	799,803	794,926	790,049	785,172	780,295	775,418	770,541	765,664	760,787	755,910	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$4,109	$4,085	$4,060	$4,035	$4,010	$3,986	$3,961	$3,936	$3,911	$3,887	$3,862	$3,837	$47,679
	b. Debt Component Grossed Up For Taxes (C)		1,107	1,101	1,094	1,087	1,081	1,074	1,067	1,061	1,054	1,047	1,041	1,034	12,848
8.	Investment Expenses														
	a. Depreciation (D)		4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	58,524
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		10,093	10,063	10,031	9,999	9,968	9,937	9,905	9,874	9,842	9,811	9,780	9,748	119,051
	a. Recoverable Costs Allocated to Energy		10,093	10,063	10,031	9,999	9,968	9,937	9,905	9,874	9,842	9,811	9,780	9,748	119,051
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		10,093	10,063	10,031	9,999	9,968	9,937	9,905	9,874	9,842	9,811	9,780	9,748	119,051
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$10,093	$10,063	$10,031	$9,999	$9,968	$9,937	$9,905	$9,874	$9,842	$9,811	$9,780	$9,748	$119,051

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 6.0912% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	
3.	Less: Accumulated Depreciation	(1,118,510)	(1,126,463)	(1,134,416)	(1,142,369)	(1,150,322)	(1,158,275)	(1,166,228)	(1,174,181)	(1,182,134)	(1,190,087)	(1,198,040)	(1,205,993)	(1,213,946)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,587,997	$1,580,044	$1,572,091	$1,564,138	$1,556,185	$1,548,232	$1,540,279	$1,532,326	$1,524,373	$1,516,420	$1,508,467	$1,500,514	$1,492,561	
6.	Average Net Investment		1,584,021	1,576,068	1,568,115	1,560,162	1,552,209	1,544,256	1,536,303	1,528,350	1,520,397	1,512,444	1,504,491	1,496,538	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$8,040	$8,000	$7,960	$7,919	$7,879	$7,839	$7,798	$7,758	$7,718	$7,677	$7,637	$7,596	$93,821
	b. Debt Component Grossed Up For Taxes (C)		2,167	2,156	2,145	2,134	2,123	2,112	2,101	2,091	2,080	2,069	2,058	2,047	25,283
8.	Investment Expenses														
	a. Depreciation (D)		7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	95,436
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		18,160	18,109	18,058	18,006	17,955	17,904	17,852	17,802	17,751	17,699	17,648	17,596	214,540
	a. Recoverable Costs Allocated to Energy		18,160	18,109	18,058	18,006	17,955	17,904	17,852	17,802	17,751	17,699	17,648	17,596	214,540
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		18,160	18,109	18,058	18,006	17,955	17,904	17,852	17,802	17,751	17,699	17,648	17,596	214,540
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$18,160	$18,109	$18,058	$18,006	$17,955	$17,904	$17,852	$17,802	$17,751	$17,699	$17,648	$17,596	$214,540

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.43 ($1,995,677) and 315.43 ($710,830).
(B) Line 6 x 6.0912% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 3.5% and 3.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
6.	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Debt Component Grossed Up For Taxes (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Investment Expenses														
	a. Depreciation (D)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.51 ($).
(B) Line 6 x 6.0912% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
6.	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Debt Component Grossed Up For Taxes (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Investment Expenses														
	a. Depreciation (D)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:
(A) Applicable depreciable base for Big Bend; account 311.52 ($25,208,869), 312.52 ($54,456,221), 315.52 ($15,914,427), and 316.52 ($958,616).
(B) Line 6 x 6.0912% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rates are 3.5%, 4.0%, 4.1% and 3.7%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
6.	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Debt Component Grossed Up For Taxes (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Investment Expenses														
	a. Depreciation (D)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.53 ($).
(B) Line 6 x 6.0912% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$1,428	$4,801	$6,274	$14,610	$19,438	$311,569	$261,768	$102,049	$52,035	$773,972
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	773,972	773,972
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$67,588,833	
3.	Less: Accumulated Depreciation	(29,385,303)	(29,577,771)	(29,770,239)	(29,962,707)	(30,155,175)	(30,347,643)	(30,540,111)	(30,732,579)	(30,925,047)	(31,117,515)	(31,309,983)	(31,502,451)	(31,694,919)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	1,428	6,229	12,503	27,113	46,551	358,120	619,888	721,937	0	
5.	Net Investment (Lines 2 + 3 + 4)	$37,429,558	$37,237,090	$37,044,622	$36,852,154	$36,661,114	$36,473,447	$36,287,253	$36,109,395	$35,936,365	$36,055,466	$36,124,766	$36,034,347	$35,893,914	
6.	Average Net Investment		37,333,324	37,140,856	36,948,388	36,756,634	36,567,280	36,380,350	36,198,324	36,022,880	35,995,915	36,090,116	36,079,556	35,964,130	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$189,504	$188,527	$187,550	$186,577	$185,616	$184,667	$183,743	$182,852	$182,715	$183,193	$183,140	$182,554	$2,220,638
	b. Debt Component Grossed Up For Taxes (C)		51,066	50,803	50,539	50,277	50,018	49,762	49,513	49,273	49,236	49,365	49,351	49,193	598,396
8.	Investment Expenses														
	a. Depreciation (D)		192,468	192,468	192,468	192,468	192,468	192,468	192,468	192,468	192,468	192,468	192,468	192,468	2,309,616
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		433,038	431,798	430,557	429,322	428,102	426,897	425,724	424,593	424,419	425,026	424,959	424,215	5,128,650
	a. Recoverable Costs Allocated to Energy		433,038	431,798	430,557	429,322	428,102	426,897	425,724	424,593	424,419	425,026	424,959	424,215	5,128,650
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		433,038	431,798	430,557	429,322	428,102	426,897	425,724	424,593	424,419	425,026	424,959	424,215	5,128,650
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$433,038	$431,798	$430,557	$429,322	$428,102	$426,897	$425,724	$424,593	$424,419	$425,026	$424,959	$424,215	$5,128,650

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.54 ($16,857,250), 312.54 ($38,069,546), 315.54 ($10,642,027), 316.54 ($687,934), 315.40 ($558,103), and 312.44 ($773,972).
(B) Line 6 x 6.0912% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 2.4%, 3.8%, 3.9%, 3.3%, 3.7%, and 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD System Reliability
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	
3.	Less: Accumulated Depreciation	(6,453,865)	(6,505,447)	(6,557,029)	(6,608,611)	(6,660,193)	(6,711,775)	(6,763,357)	(6,814,939)	(6,866,521)	(6,918,103)	(6,969,685)	(7,021,267)	(7,072,849)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$18,013,941	$17,962,359	$17,910,777	$17,859,195	$17,807,613	$17,756,031	$17,704,449	$17,652,867	$17,601,285	$17,549,703	$17,498,121	$17,446,539	$17,394,957	
6.	Average Net Investment		17,988,150	17,936,568	17,884,986	17,833,404	17,781,822	17,730,240	17,678,658	17,627,076	17,575,494	17,523,912	17,472,330	17,420,748	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$91,308	$91,046	$90,784	$90,522	$90,261	$89,999	$89,737	$89,475	$89,213	$88,951	$88,690	$88,428	$1,078,414
	b. Debt Component Grossed Up For Taxes (C)		24,605	24,534	24,464	24,393	24,323	24,252	24,181	24,111	24,040	23,970	23,899	23,829	290,601
8.	Investment Expenses														
	a. Depreciation (D)		51,582	51,582	51,582	51,582	51,582	51,582	51,582	51,582	51,582	51,582	51,582	51,582	618,984
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		167,495	167,162	166,830	166,497	166,166	165,833	165,500	165,168	164,835	164,503	164,171	163,839	1,987,999
	a. Recoverable Costs Allocated to Energy		167,495	167,162	166,830	166,497	166,166	165,833	165,500	165,168	164,835	164,503	164,171	163,839	1,987,999
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		167,495	167,162	166,830	166,497	166,166	165,833	165,500	165,168	164,835	164,503	164,171	163,839	1,987,999
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$167,495	$167,162	$166,830	$166,497	$166,166	$165,833	$165,500	$165,168	$164,835	$164,503	$164,171	$163,839	$1,987,999

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.45 ($23,011,597) and 312.44 ($1,456,209).
(B) Line 6 x 6.0912% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 2.5% and 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Mercury Air Toxics Standards (MATS)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	13,614	0	0	0	0	0	13,614
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$8,621,413	$8,621,413	$8,621,413	$8,621,413	$8,621,413	$8,621,413	$8,621,413	$8,635,028	$8,635,028	$8,635,028	$8,635,028	$8,635,028	$8,635,028	
3.	Less: Accumulated Depreciation	(1,955,259)	(1,977,555)	(1,999,851)	(2,022,147)	(2,044,443)	(2,066,739)	(2,089,035)	(2,111,331)	(2,133,666)	(2,156,001)	(2,178,336)	(2,200,671)	(2,223,006)	
4.	CWIP - Non-Interest Bearing	13,614	13,614	13,614	13,614	13,614	13,614	13,614	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$6,679,769	$6,657,473	$6,635,177	$6,612,881	$6,590,585	$6,568,289	$6,545,993	$6,523,697	$6,501,362	$6,479,027	$6,456,692	$6,434,357	$6,412,022	
6.	Average Net Investment		6,668,621	6,646,325	6,624,029	6,601,733	6,579,437	6,557,141	6,534,845	6,512,529	6,490,194	6,467,859	6,445,524	6,423,189	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$33,850	$33,737	$33,624	$33,510	$33,397	$33,284	$33,171	$33,058	$32,944	$32,831	$32,717	$32,604	$398,727
	b. Debt Component Grossed Up For Taxes (C)		9,122	9,091	9,061	9,030	9,000	8,969	8,939	8,908	8,878	8,847	8,816	8,786	107,447
8.	Investment Expenses														
	a. Depreciation (D)		22,296	22,296	22,296	22,296	22,296	22,296	22,296	22,335	22,335	22,335	22,335	22,335	267,747
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		65,268	65,124	64,981	64,836	64,693	64,549	64,406	64,301	64,157	64,013	63,868	63,725	773,921
	a. Recoverable Costs Allocated to Energy		65,268	65,124	64,981	64,836	64,693	64,549	64,406	64,301	64,157	64,013	63,868	63,725	773,921
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		65,268	65,124	64,981	64,836	64,693	64,549	64,406	64,301	64,157	64,013	63,868	63,725	773,921
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$65,268	$65,124	$64,981	$64,836	$64,693	$64,549	$64,406	$64,301	$64,157	$64,013	$63,868	$63,725	$773,921

Notes:

(A) Applicable depreciable base for Big Bend and Polk; accounts 312.44 ($3,427,481), 341.80 ($26,150), 315.40 ($1,226,949), 315.41 ($138,853), 315.42 ($138,853), 312.45 ($2,053,017), 312.46 ($1,242,315), 315.44 ($16,035), 315.45 ($40,217), 315.46 ($50,784), 311.40 ($13,216), 345.81 ($2,232), 312.54 ($210,295), 312.40 ($13,614), and 395.00 ($35,018).
(B) Line 6 x 6.0912% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 3.0%, 2.2%, 3.7%, 3.5%, 3.3%, 2.5%, 3.3%, 3.2%, 3.1%, 3.5%, 2.9%, 3.3%, 3.8%, 3.4%, and 14.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

For Project: SO_2 Emissions Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Purchases/Transfers		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Working Capital Balance														
	a. FERC 158.1 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
	b. FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c. FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d. FERC 254.01 Regulatory Liabilities - Gains	(34,249)	(34,238)	(34,238)	(34,238)	(34,225)	(34,225)	(34,225)	(34,213)	(34,213)	(34,213)	(34,201)	(34,201)	(34,201)	
3.	Total Working Capital Balance	($34,249)	($34,238)	($34,238)	($34,238)	($34,225)	($34,225)	($34,225)	($34,213)	($34,213)	($34,213)	($34,201)	($34,201)	($34,201)	
4.	Average Net Working Capital Balance		($34,244)	($34,238)	($34,238)	($34,232)	($34,225)	($34,225)	($34,219)	($34,213)	($34,213)	($34,207)	($34,201)	($34,201)	
5.	Return on Average Net Working Capital Balance														
	a. Equity Component Grossed Up For Taxes (A)		($174)	($174)	($174)	($174)	($174)	($174)	($174)	($174)	($174)	($174)	($174)	($174)	(2,088)
	b. Debt Component Grossed Up For Taxes (B)		(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(564)
6.	Total Return Component		(221)	(221)	(221)	(221)	(221)	(221)	(221)	(221)	(221)	(221)	(221)	(221)	(2,652)
7.	Expenses:		1	2	3	4	5	6	7	8	9	10	11	12	
	a. Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. SO_2 Allowance Expense		(6)	11	9	(11)	5	14	(5)	7	7	(5)	7	7	41
8.	Net Expenses (D)		(6)	11	9	(11)	5	14	(5)	7	7	(5)	7	7	41
9.	Total System Recoverable Expenses (Lines 6 + 8)		(227)	(210)	(212)	(232)	(216)	(207)	(226)	(214)	(214)	(226)	(214)	(214)	(2,611)
	a. Recoverable Costs Allocated to Energy		(227)	(210)	(212)	(232)	(216)	(207)	(226)	(214)	(214)	(226)	(214)	(214)	(2,611)
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		(227)	(210)	(212)	(232)	(216)	(207)	(226)	(214)	(214)	(226)	(214)	(214)	(2,612)
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Juris. Recoverable Costs (Lines 12 + 13)		($227)	($210)	($212)	($232)	($216)	($207)	($226)	($214)	($214)	($226)	($214)	($214)	($2,612)

Notes:
(A) Line 6 x 6.0912% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(B) Line 6 x 1.6414% x 1/12
(C) Line 6 is reported on Schedule 7E.
(D) Line 8 is reported on Schedule 5E.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Gypsum Storage Facility
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	
3.	Less: Accumulated Depreciation	(3,777,423)	(3,829,302)	(3,881,181)	(3,933,060)	(3,984,939)	(4,036,818)	(4,088,697)	(4,140,576)	(4,192,455)	(4,244,334)	(4,296,213)	(4,348,092)	(4,399,971)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$17,689,936	$17,638,057	$17,586,178	$17,534,299	$17,482,420	$17,430,541	$17,378,662	$17,326,783	$17,274,904	$17,223,025	$17,171,146	$17,119,267	$17,067,388	
6.	Average Net Investment		17,663,997	17,612,118	17,560,239	17,508,360	17,456,481	17,404,602	17,352,723	17,300,844	17,248,965	17,197,086	17,145,207	17,093,328	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$89,662	$89,399	$89,136	$88,872	$88,609	$88,346	$88,082	$87,819	$87,556	$87,292	$87,029	$86,766	$1,058,568
	b. Debt Component Grossed Up For Taxes (C)		24,161	24,090	24,019	23,949	23,878	23,807	23,736	23,665	23,594	23,523	23,452	23,381	285,255
8.	Investment Expenses														
	a. Depreciation (D)		51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	622,548
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		165,702	165,368	165,034	164,700	164,366	164,032	163,697	163,363	163,029	162,694	162,360	162,026	1,966,371
	a. Recoverable Costs Allocated to Energy		165,702	165,368	165,034	164,700	164,366	164,032	163,697	163,363	163,029	162,694	162,360	162,026	1,966,371
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		165,702	165,368	165,034	164,700	164,366	164,032	163,697	163,363	163,029	162,694	162,360	162,026	1,966,371
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$165,702	$165,368	$165,034	$164,700	$164,366	$164,032	$163,697	$163,363	$163,029	$162,694	$162,360	$162,026	$1,966,371

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.40
(B) Line 6 x 6.0912% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 2.9%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Coal Combustion Residual Rule (CCR Rule)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$797,231	$159,684	$213,313	$1,975	$30,092	$21,491	$93,819	$0	$0	$0	$0	$0	$1,317,604
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	2,178,467	0	794,761	2,973,228
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$930,303	$930,303	$930,303	$930,303	$930,303	$930,303	$930,303	$930,303	$930,303	$930,303	$3,108,770	$3,108,770	$3,903,531	
3.	Less: Accumulated Depreciation	(77,769)	(80,073)	(82,377)	(84,681)	(86,985)	(89,289)	(91,593)	(93,897)	(96,201)	(98,505)	(100,809)	(109,285)	(117,761)	
4.	CWIP - Non-Interest Bearing	1,655,624	2,452,855	2,612,539	2,825,852	2,827,827	2,857,919	2,879,409	2,973,228	2,973,228	2,973,228	794,761	794,761	0	
5.	Net Investment (Lines 2 + 3 + 4)	$2,508,158	$3,303,085	$3,460,465	$3,671,474	$3,671,145	$3,698,933	$3,718,119	$3,809,634	$3,807,330	$3,805,026	$3,802,722	$3,794,246	$3,785,770	
6.	Average Net Investment		2,905,622	3,381,775	3,565,970	3,671,309	3,685,039	3,708,526	3,763,877	3,808,482	3,806,178	3,803,874	3,798,484	3,790,008	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$14,749	$17,166	$18,101	$18,636	$18,705	$18,824	$19,105	$19,332	$19,320	$19,308	$19,281	$19,238	$221,765
	b. Debt Component Grossed Up For Taxes (C)		3,974	4,626	4,878	5,022	5,041	5,073	5,148	5,209	5,206	5,203	5,196	5,184	59,760
8.	Investment Expenses														
	a. Depreciation (D)		2,304	2,304	2,304	2,304	2,304	2,304	2,304	2,304	2,304	2,304	8,476	8,476	39,992
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		21,027	24,096	25,283	25,962	26,050	26,201	26,557	26,845	26,830	26,815	32,953	32,898	321,517
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		21,027	24,096	25,283	25,962	26,050	26,201	26,557	26,845	26,830	26,815	32,953	32,898	321,517
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		21,027	24,096	25,283	25,962	26,050	26,201	26,557	26,845	26,830	26,815	32,953	32,898	321,517
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$21,027	$24,096	$25,283	$25,962	$26,050	$26,201	$26,557	$26,845	$26,830	$26,815	$32,953	$32,898	$321,517

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.40 ($261,568), 312.44 ($668,735) and 312.40 ($2,973,228).
(B) Line 6 x 6.0912% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is 2.9%, 3.0% and 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Coal Combustion Residuals (CCR Rule - Phase II)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$14,692	$36,627	$4,051	$4,190	$7,631	$7,380	$258,399	$264,350	$255,950	$0	$0	($0)	$853,269
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	2,009,031	0	(0)	2,009,031
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,009,031	$2,009,031	$2,009,031	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	(5,023)	(10,046)	
4.	CWIP - Non-Interest Bearing	1,155,762	1,170,454	1,207,080	1,211,131	1,215,321	1,222,952	1,230,332	1,488,731	1,753,081	2,009,031	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,155,762	$1,170,454	$1,207,080	$1,211,131	$1,215,321	$1,222,952	$1,230,332	$1,488,731	$1,753,081	$2,009,031	$2,009,031	$2,004,008	$1,998,985	
6.	Average Net Investment		1,163,108	1,188,767	1,209,106	1,213,226	1,219,137	1,226,642	1,359,532	1,620,906	1,881,056	2,009,031	2,006,520	2,001,497	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$5,904	$6,034	$6,137	$6,158	$6,188	$6,226	$6,901	$8,228	$9,548	$10,198	$10,185	$10,160	$91,867
	b. Debt Component Grossed Up For Taxes (C)		1,591	1,626	1,654	1,659	1,668	1,678	1,860	2,217	2,573	2,748	2,745	2,738	24,757
8.	Investment Expenses														
	a. Depreciation (D)		0	0	0	0	0	0	0	0	0	0	5,023	5,023	10,046
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		7,495	7,660	7,791	7,817	7,856	7,904	8,761	10,445	12,121	12,946	17,953	17,921	126,670
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		7,495	7,660	7,791	7,817	7,856	7,904	8,761	10,445	12,121	12,946	17,953	17,921	126,670
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		7,495	7,660	7,791	7,817	7,856	7,904	8,761	10,445	12,121	12,946	17,953	17,921	126,670
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$7,495	$7,660	$7,791	$7,817	$7,856	$7,904	$8,761	$10,445	$12,121	$12,946	$17,953	$17,921	$126,670

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.44.
(B) Line 6 x 6.0912% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate 3.0%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend ELG Compliance
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$136,645	$141,845	$267,978	$8,948	$417,361	$607,383	$1,185,199	$660,199	$1,105,199	$3,107,983	$1,590,199	$1,480,199	$10,709,141
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	2,522,506	2,659,151	2,800,997	3,068,975	3,077,923	3,495,285	4,102,668	5,287,867	5,948,066	7,053,265	10,161,248	11,751,447	13,231,646	
5.	Net Investment (Lines 2 + 3 + 4)	$2,522,506	$2,659,151	$2,800,997	$3,068,975	$3,077,923	$3,495,285	$4,102,668	$5,287,867	$5,948,066	$7,053,265	$10,161,248	$11,751,447	$13,231,646	
6.	Average Net Investment		2,590,828	2,730,074	2,934,986	3,073,449	3,286,604	3,798,976	4,695,267	5,617,966	6,500,666	8,607,257	10,956,347	12,491,547	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$13,151	$13,858	$14,898	$15,601	$16,683	$19,284	$23,833	$28,517	$32,997	$43,690	$55,614	$63,407	$341,533
	b. Debt Component Grossed Up For Taxes (C)		3,544	3,734	4,015	4,204	4,496	5,196	6,422	7,684	8,892	11,773	14,986	17,086	92,032
8.	Investment Expenses														
	a. Depreciation (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		16,695	17,592	18,913	19,805	21,179	24,480	30,255	36,201	41,889	55,463	70,600	80,493	433,565
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		16,695	17,592	18,913	19,805	21,179	24,480	30,255	36,201	41,889	55,463	70,600	80,493	433,565
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		16,695	17,592	18,913	19,805	21,179	24,480	30,255	36,201	41,889	55,463	70,600	80,493	433,565
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$16,695	$17,592	$18,913	$19,805	$21,179	$24,480	$30,255	$36,201	$41,889	$55,463	$70,600	$80,493	$433,565

Notes:
(A) Applicable depreciable base for Big Bend; accounts TBD depending on type of plant added
(B) Line 6 x 6.0912% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is TBD depending on type of plant added
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Section 316(b) Impingement Mortality
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$468,674	$278,711	$1,919,704	$297,640	$311,598	$951,231	$873,244	$1,030,395	$2,044,496	$2,097,870	$1,065,476	$459,856	$11,798,893
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	1,072,932	1,541,605	1,820,317	3,740,021	4,037,660	4,349,259	5,300,489	6,173,733	7,204,128	9,248,624	11,346,494	12,411,969	12,871,825	
5.	Net Investment (Lines 2 + 3 + 4)	$1,072,932	$1,541,605	$1,820,317	$3,740,021	$4,037,660	$4,349,259	$5,300,489	$6,173,733	$7,204,128	$9,248,624	$11,346,494	$12,411,969	$12,871,825	
6.	Average Net Investment		1,307,269	1,680,961	2,780,169	3,888,841	4,193,459	4,824,874	5,737,111	6,688,931	8,226,376	10,297,559	11,879,231	12,641,897	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$6,636	$8,533	$14,112	$19,740	$21,286	$24,491	$29,122	$33,953	$41,757	$52,270	$60,299	$64,170	$376,369
	b. Debt Component Grossed Up For Taxes (C)		1,788	2,299	3,803	5,319	5,736	6,600	7,847	9,149	11,252	14,085	16,249	17,292	101,419
8.	Investment Expenses														
	a. Depreciation (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		8,424	10,832	17,915	25,059	27,022	31,091	36,969	43,102	53,009	66,355	76,548	81,462	477,788
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		8,424	10,832	17,915	25,059	27,022	31,091	36,969	43,102	53,009	66,355	76,548	81,462	477,788
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		8,424	10,832	17,915	25,059	27,022	31,091	36,969	43,102	53,009	66,355	76,548	81,462	477,788
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$8,424	$10,832	$17,915	$25,059	$27,022	$31,091	$36,969	$43,102	$53,009	$66,355	$76,548	$81,462	$477,788

Notes:
(A) Applicable depreciable base for Big Bend; accounts TBD depending on type of plant added
(B) Line 6 x 6.0912% x 1/12. Based on ROE of 9.95% and weighted income tax rate of 25.345% (expansion factor of 1.34315)
(C) Line 6 x 1.6414% x 1/12
(D) Applicable depreciation rate is TBD depending on type of plant added
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2021 to December 2021

Form 42 - 9E

Calculation of Revenue Requirement Rate of Return
(in Dollars)

	(1)	(2)	(3)	(4)
	Jurisdictional Rate Base **2021 Adj. FESR** ($000)	Ratio %	Cost Rate %	Weighted Cost Rate %
Long Term Debt	$ 2,398,774	33.85%	4.34%	1.4692%
Short Term Debt	299,519	4.23%	1.06%	0.0448%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	86,301	1.22%	2.44%	0.0297%
Common Equity	3,147,963	44.43%	9.95%	4.4204%
Accum. Deferred Inc. Taxes & Zero Cost ITC's	948,501	13.39%	0.00%	0.0000%
Deferred ITC - Weighted Cost	204,707	2.89%	7.35%	0.2123%
Total	$ 7,085,765	100.00%		6.18%

ITC split between Debt and Equity:

Long Term Debt	$ 2,398,774	Long Term Debt	46.00%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	3,147,963	Equity - Common	54.00%
Total	$ 5,546,737	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = 0.2123% * 46.00%	0.0977%
Equity = 0.2123% * 54.00%	0.1146%
Weighted Cost	0.2123%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.4204%
Deferred ITC - Weighted Cost	0.1146%
	4.5350%
Times Tax Multiplier	1.34315
Total Equity Component	6.0912%

Total Debt Cost Rate:

Long Term Debt	1.4692%
Short Term Debt	0.0448%
Customer Deposits	0.0297%
Deferred ITC - Weighted Cost	0.0977%
Total Debt Component	1.6414%
Total Cost of Capital	7.7326%

Notes:
Column (1) - Per Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology.
Column (2) - Column (1) / Total Column (1)
Column (3) - Per Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology.
Column (4) - Column (2) x Column (3)