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July 25, 2018

VIA: ELECTRONIC FILING

Ms. Carlotta S. Stauffer
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Environmental Cost Recovery Clause
FPSC Docket No. 20180007-EI

Dear Ms. Stauffer:

Attached for filing in the above docket, on behalf of Tampa Electric Company, is the following:

1. Petition of Tampa Electric Company.

2. Prepared Direct Testimony and Exhibits (PAR-2) and (PAR-3) of Penelope A. Rusk regarding Environmental Cost Recovery Actual/Estimated True-up for the period January 2018 through December 2018.

3. Prepared Direct Testimony of Paul L. Carpinone regarding Environmental Cost Recovery Actual/Estimated True-up for the period January 2018 through December 2018.

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Attachment

cc: All Parties of Record (w/attachment)

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Petition and Testimonies, filed on behalf of Tampa Electric Company, has been furnished by electronic mail on this 25th day of July 2018 to the following:

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ATTORNEY

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause.	)))	DOCKET NO. 20180007-EI FILED: July 25, 2018

PETITION OF TAMPA ELECTRIC COMPANY

Tampa Electric Company ("Tampa Electric" or "company"), hereby petitions the Commission for approval of the company's actual/estimated environmental cost recovery true-up amount for the period January 2018 through December 2018, and in support thereof, says:

Environmental Cost Recovery

1. Tampa Electric projects an actual/estimated true-up amount for the January 2018 through December 2018 period, which is based on actual data for the period January 1, 2018 through June 30, 2018 and revised estimates for the period July 1, 2018 through December 31, 2018, to be an over-recovery of $13,471,786. (See Exhibit No. PAR-2, Document No. 1, Schedule 42-1E)

2. For reasons more fully detailed in the Prepared Direct Testimony of witness Penelope A. Rusk and Paul L. Carpinone, the environmental compliance costs sought to be approved for cost recovery proposed in this petition are consistent with the provisions of Section 366.8255, Florida Statutes, and with prior rulings by the Commission with respect to environmental compliance cost recovery for Tampa Electric and other investor-owned utilities.

3. Tampa Electric is not aware of any disputed issues of material fact regarding any of the matters stated or relief requested in this petition.

WHEREFORE, Tampa Electric Company requests this Commission's approval of the company's actual/estimated environmental cost recovery true-up calculations for the period January 1, 2018 through December 31, 2018.

DATED this 25th day of July 2018.

Respectfully submitted,

JAMES D. BEASLEY
J. JEFFRY WAHLEN
Ausley McMullen
Post Office Box 391
Tallahassee, FL 32302
(850) 224-9115

ATTORNEYS FOR TAMPA ELECTRIC COMPANY

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Petition, filed on behalf of Tampa Electric Company, has been furnished by electronic mail on this 25th day of July 2018 to the following:

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ATTORNEY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20180007-EI

IN RE: TAMPA ELECTRIC'S ENVIRONMENTAL COST RECOVERY

ACTUAL/ESTIMATED TRUE-UP

JANUARY 2018 THROUGH DECEMBER 2018

TESTIMONY AND EXHIBITS

OF

PENELOPE A. RUSK

FILED: JULY 25, 2018

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PENELOPE A. RUSK

Q. Please state your name, address, occupation and employer.

A. My name is Penelope A. Rusk. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Rates in the Regulatory Affairs department.

Q. Have you previously filed testimony in Docket No. 20180007-EI?

A. Yes, I submitted direct testimony on April 2, 2018.

Q. Has your job description, education, or professional experience changed since then?

A. No.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the calculation of the January 2018 through December 2018 actual/estimated true-up amount to be refunded or recovered through the Environmental Cost Recovery Clause ("ECRC") during the period January 2019 through December 2019. My testimony addresses the recovery of capital and operations and maintenance ("O&M") costs associated with environmental compliance activities for 2018, based on six months of actual data and six months of estimated data. This information will be used in the determination of the environmental cost recovery factors for January 2019 through December 2019.

Q. Have you prepared exhibits that show the recoverable environmental costs for the actual/estimated period of January 2018 through December 2018?

A. Yes, I prepared two exhibits. Exhibit No. PAR-2, containing nine documents, was prepared under my direction and supervision. It includes Forms 42-1E through 42-9E, which show the current period actual/estimated true-up amount to be used in calculating the cost recovery factors for January 2019 through December 2019. Exhibit No. PAR-3, which contains seven documents, includes selected schedules without the costs of Tampa Electric's two new proposed ECRC projects for compliance with the Effluent Limitations Guidelines ("ELG") Rule and Section 316(b) of the Clean Water Act.

Q. What has Tampa Electric calculated as the actual/estimated true-up for the current period to be applied.

A. The actual/estimated true-up applicable for the current period, January 2018 through December 2018, is an over-recovery of $13,471,786. A detailed calculation supporting the true-up amount is shown on Forms 42-1E through 42-9E of my exhibit.

Q. Is Tampa Electric including costs in the actual/estimated true-up filing for any new environmental projects that were not anticipated and included in its 2018 ECRC factors?

A. Yes, Tampa Electric included costs associated with the company's compliance with Section 316(b) of the Clean Water Act. The company's petition for approval to recover such costs through the ECRC was filed on April 26, 2018. In addition, new costs for compliance with the ELG Rule are included. The company's petition for approval to recover such costs through the ECRC was filed on May 9, 2018. The respective petitions explain the need for the projects and the regulations requiring those activities. The testimony of Tampa Electric witness Paul L. Carpinone submitted concurrently in this docket also supports these projects.

Q. What depreciation rates were utilized for the capital projects contained in the 2018 actual/estimated true-up?

A. Tampa Electric utilized the depreciation rates approved in Order No. PSC-2012-0175-PAA-EI, issued on April 3, 2012, in Docket No. 20110131-EI, with two exceptions. For the Big Bend Fuel Oil Tank No. 1 Upgrade and Big Bend Fuel Oil Tank No. 2 Upgrade projects, the company has utilized depreciation rates calculated to recover the remaining net investment balances of these now-retired assets from July 2018 through December 2021, which represents a five-year period from the date of their retirement on December 31, 2016. Tampa Electric requests approval for this treatment as it is consistent with Commission-approved treatment for other assets retired before the end of their projected depreciable life over a five-year period from the date of retirement. For example, the accelerated recovery of the remaining net investment balance of the Gannon Ignition Oil Tank project over a five-year period was authorized by Commission Order No. PSC-2000-2391-FOF-EI, issued December 13, 2000 in Docket No. 20000007-EI.

Q. Why were the assets of the Big Bend Fuel Oil Tank No. 1 Upgrade and Big Bend Fuel Oil Tank No. 2 Upgrade projects retired earlier than expected?

A. The assets were retired December 31, 2016 after an analysis of the expenses to maintain them and consideration of the low utilization of oil at the station after the Big Bend igniters on Units 1 through 4 were converted to natural gas operation. In 2016, the maintenance cost to bring the 4.5 million-gallon tank system to current standards was estimated at $1.5 million. Annual monitoring and reporting costs were approximately $50,000 to $75,000. In light of these substantial costs and the fact that oil use at the station was greatly reduced after the igniters conversion in 2015, so that a large amount of oil storage was no longer needed, Tampa Electric retired the assets. With the retirement, Tampa Electric was no longer required to fill the tank with now-unneeded amounts of No. 2 fuel oil at the start of each hurricane season to prevent the tank from floating in the event of storm related flooding. Finally, retiring the tank avoided the continued environmental costs and risks of managing a tank of this size in proximity to the waters of the State.

Q. What capital structure, components and cost rates did Tampa Electric rely on to calculate the revenue requirement rate of return for January 2018 through December 2018?

A. Tampa Electric's revenue requirement rate of return for January 2018 through December 2018 is calculated based on the capital structure, components and current period cost rates as approved in Order No. PSC-2012-0425-PAA-EU, issued on August 16, 2012 in Docket No. 20120007-EI. The calculation of the revenue requirement rate of return is shown on Form 42-9E.

Q. Has Tampa Electric adjusted the revenue requirements of its ECRC capital projects to reflect the lower tax rate of 21 percent in the Tax Cuts and Jobs Act of 2017 ("TCJA")?

A. Yes, the company updated the tax multiplier utilized in the determination of the equity component of the revenue requirement rate of return, shown on Form 42-9E, Document

No. 9 of my Exhibit No. PAR-2.

Q. Did the company apply the lower tax rate in the calculation of revenue requirements for its ECRC capital projects for the period January 2018 through December 2018?

A. Yes. Tampa Electric calculated the new tax multiplier and revised rate of return in early 2018 and began applying the rate to the monthly ECRC net investment balances in May 2018. The company calculated an adjustment to reflect revenue requirements with the lower tax rate for the months of January 2018 through April 2018 and booked the adjustment, including interest, in May 2018. This tax adjustment effectively identified and recorded the difference in the amount of allowed cost recovery for environmental projects due to the lower tax rate as an over-recovery for the first four months of 2018 that will be considered as part of the company's projected overall over- or under-recovery for the year.

Form 42-8E, which is included as Document No. 8 of Exhibit No. PAR-2, shows the calculation of the adjusted monthly revenue requirements for capital projects using the lower tax rate and revised rate of return for the January through December 2018 period.

Q. Will the company account for the flowback of excess accumulated deferred income taxes associated with environmental projects in this docket or as part of Docket No. 20180045-EI, which addresses the overall impact of the TCJA on the company?

A. The flowback of excess accumulated deferred income taxes associated with environmental projects recovered through the environmental cost recovery clause is being addressed in Docket No. 20180045-EI and does not need to be considered in this docket.

Q. How did the actual/estimated project expenditures for the January 2018 through December 2018 period compare with the company’s original projections?

A. As shown on Form 42-4E, total O&M costs are expected to be $9,400,732 less than the amount that was originally projected. The total capital expenditures itemized on Form 42-6E, are expected to be $4,523,197 less than originally projected. Significant variances for O&M costs and capital project amounts are explained below.

O&M Project Variances

O&M expense projections related to planned maintenance work are typically spread across the period in question. However, the company always inspects the units to ensure that the maintenance is needed, before beginning work. The need varies according to the actual usage and associated "wear and tear" on the units. If inspection indicates that the maintenance is not yet needed or if additional work is needed, then the company will have a variance compared to the projection. When inspections indicate that work is not needed now, that maintenance expense will be incurred in a future period when warranted by the condition of the unit.

- **Big Bend Unit 3 Flue Gas Desulfurization ("FGD") Integration:** The Bend Unit 3 FGD Integration Project variance is estimated to be $2,529,108 or 57.2 percent less than projected due to greater operation on natural gas, compared to the original projection. This reduces the expected need for consumables and maintenance.

- **Big Bend Units 1 & 2 FGD:** The Big Bend Units 1 & 2 FGD project variance is estimated to be $1,629,196 or 74.1 percent less than projected. The variance is due to lower costs for consumables and maintenance than expected as the units burned natural gas.

- **Big Bend PM Minimization & Monitoring:** The Big Bend PM Minimization & Monitoring Project variance is estimated to be $204,721 or 33.5 percent lower than projected. This variance is due to less maintenance being required than expected, after inspection.

- **Big Bend NO_x Emissions Reduction:** The Big Bend NO_x Emissions Reduction project variance is $60,263 or 43.4 percent less than projected. This variance is due to the operation of Big Bend Units 1 & 2 on natural gas.

- **Bayside Selective Catalytic Reduction ("SCR") Consumables:** The Bayside SCR Consumables project variance is estimated to be $92,779 or 45.5 percent less than projected. This variance is due to less total run time estimated for Bayside Station units, compared to the original projection, resulting in less ammonia consumption.

- **Clean Water Act Section 316(b) Phase II Study Program:** The Clean Water Act Section 316(b) Phase II Study Program project variance is $246,842 or 76.9 percent less than projected. The National Pollutant Discharge

Elimination System ("NPDES") permit renewal for Big Bend Station has not yet been finalized. The variance is related to uncertainty regarding the timing of the final requirements and reporting that must be submitted once the permit is finalized.

- **Big Bend Unit 1 SCR:** The Big Bend Unit 1 SCR project variance is $1,147,483 or 76.6 percent less than originally projected. This variance is due to operation of the unit on natural gas, which reduced the unit's need for consumables and maintenance work, compared to the original projection.

- **Big Bend Unit 2 SCR:** The Big Bend Unit 2 SCR project variance is $1,268,864 or 77.8 percent less than originally projected. This variance is due to operation of the unit on natural gas, which reduced the use of consumables and need for maintenance work, compared to the original projection.

- **Big Bend Unit 3 SCR:** The Big Bend Unit 3 SCR project variance is $141,390 or 8.3 percent less than projected. This variance is due to greater operation on natural gas, compared to the original projection.

- **Big Bend Unit 4 SCR:** The Big Bend Unit 4 SCR project variance is $410,017 or 38.6 percent less than projected. This variance is due to less total run time estimated when compared to the original projection.

- **Mercury Air Toxics Standards:** The Mercury Air Toxics Standards project variance is $206,622 or 89.4 percent less than projected. Both Polk and Big Bend Power Stations achieved Low Emitting Electric Generating Unit status in 2017. As a result, monitoring is not required at this time, only periodic testing, and the costs were lower than originally projected.

- **Big Bend ELG Rule Study:** The Big Bend ELG Study project variance is $54,007 greater than projected. This variance is due to a delay in completing the study, compared to the original projection. The study has now been completed.

- **CCR Rule – Phase II:** The Big Bend Coal Combustion Residual ("CCR") Rule Phase II project variance is $1,367,762 or 22.3 percent less than projected. This variance is due to timing differences in the project schedule when compared to the original projection. Dewatering activities, which must occur before the CCR disposal, have occurred more slowly than originally projected. The project expenditures are still needed and will be incurred in the future.

Capital Project Variances

There were significant capital variances for the projects listed below, each of which was due to the TCJA tax rate change from 35 percent to 21 percent.

- Big Bend Unit 3 Flue Gas Desulfurization ("FGD") Integration
- Big Bend Units 1 & 2 FGD
- BIG Bend FGD Optimization and Utilization
- Big Bend NOx Emissions Reduction
- Big Bend Particulate Matter Minimization
- Big Bend Unit 1 SCR
- Big Bend Unit 2 SCR
- Big Bend Unit 3 SCR
- Big Bend Unit 4 SCR
- Big Bend FGD System Reliability
- Mercury Air Toxics Standards
- Big Bend Gypsum Storage Facility
- CCR Rule – Phase I

As I stated earlier, Tampa Electric updated the tax multiplier utilized in the determination of the equity component of the revenue requirement rate of return and applied the lower tax rate in the calculation of revenue requirements for the ECRC capital projects for the period January 2018 through December 2018.

Q. Does this conclude your direct testimony?

A. Yes, it does.

INDEX

TAMPA ELECTRIC COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE

ACTUAL/ESTIMATED TRUE-UP AMOUNT
FOR THE PERIOD
JANUARY 2018 THROUGH DECEMBER 2018

FORMS 42-1E THROUGH 42-9E

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2018 to December 2018
(in Dollars)

Form 42 - 1E

Line	Period Amount
1. Over/(Under) Recovery for the Current Period (Form 42-2E, Line 5)	$13,259,531
2. Interest Provision (Form 42-2E, Line 6)	212,255
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 2019 to December 2019 (Lines 1 + 2 + 3)	$13,471,786

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2018 to December 2018

Form 42 - 2E

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)	$5,299,826	$4,794,184	$4,754,839	$4,804,461	$5,074,853	$5,873,006	$6,540,375	$6,493,000	$6,689,809	$5,928,024	$4,939,446	$4,863,661	$66,055,485
2.	True-Up Provision	508,445	508,445	508,445	508,445	508,445	508,445	508,445	508,445	508,445	508,445	508,445	508,449	6,101,344
3.	ECRC Revenues Applicable to Period (Lines 1 + 2) [1]	5,808,271	5,302,629	5,263,284	5,312,906	5,583,298	6,381,451	7,048,820	7,001,445	7,198,254	6,436,469	5,447,891	5,372,110	72,156,829
4.	Jurisdictional ECRC Costs													
	a. O & M Activities (Form 42-5E, Line 9)	1,874,870	2,166,060	1,373,137	959,540	1,185,543	743,043	405,177	403,175	395,441	910,226	1,021,725	1,269,328	12,707,265
	b. Capital Investment Projects (Form 42-7E, Line 9)	3,891,399	3,881,399	3,871,500	3,861,963	3,853,761	3,845,686	3,837,676	3,832,830	3,832,706	3,832,257	3,827,035	3,821,820	46,190,032
	c. Total Jurisdictional ECRC Costs	5,766,269	6,047,459	5,244,637	4,821,503	5,039,304	4,588,729	4,242,853	4,236,005	4,228,147	4,742,483	4,848,760	5,091,148	58,897,297
5.	Over/Under Recovery (Line 3 - Line 4c) [1]	42,002.00	(744,830)	18,647	491,403	543,994.00	1,792,722.00	2,805,967.00	2,765,440.00	2,970,107.00	1,693,986.00	599,131.00	280,962	13,259,531
6.	Interest Provision (Form 42-3E, Line 10)	9,356	8,341	8,197	8,382	8,410	9,750	14,605	20,780	25,636	30,994	33,941	33,863	212,255
7.	Beginning Balance True-Up & Interest Provision [1]	6,101,344	5,644,257	4,399,323	3,917,722	3,909,062	3,953,021	5,247,048	7,559,175	9,836,950	12,324,248	13,540,783	13,665,410	6,101,344
	a. Deferred True-Up from January to December 2018 (Order No. PSC-2018-0014-FOF-EI)	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666
8.	True-Up Collected/(Refunded) (see Line 2)	(508,445)	(508,445)	(508,445)	(508,445)	(508,445)	(508,445)	(508,445)	(508,445)	(508,445)	(508,445)	(508,445)	(508,449)	(6,101,344)
9.	End of Period Total True-Up (Lines 5+6+7+7a+8) [1]	7,142,923	5,897,989	5,416,388	5,407,728	5,451,687	6,745,714	9,057,841	11,335,616	13,822,914	15,039,449	15,164,076	14,970,452	14,970,452
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]	$7,142,923	$5,897,989	$5,416,388	$5,407,728	$5,451,687	$6,745,714	$9,057,841	$11,335,616	$13,822,914	$15,039,449	$15,164,076	$14,970,452	$14,970,452

Form 42 - 3E

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2018 to December 2018

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 42-2E, Line 7 + 7a + 10)	$7,600,010	$7,142,923	$5,897,989	$5,416,388	$5,407,728	$5,451,687	$6,745,714	$9,057,841	$11,335,616	$13,822,914	$15,039,449	$15,164,076	
2.	Ending True-Up Amount Before Interest	7,133,567	5,889,648	5,408,191	5,399,346	5,443,277	6,735,964	9,043,236	11,314,836	13,797,278	15,008,455	15,130,135	14,936,589	
3.	Total of Beginning & Ending True-Up (Lines 1 + 2) [1]	14,733,577	13,032,571	11,306,180	10,815,734	10,851,005	12,187,651	15,788,950	20,372,677	25,132,894	28,831,369	30,169,584	30,100,665	
4.	Average True-Up Amount (Line 3 x 1/2) [1]	7,366,789	6,516,286	5,653,090	5,407,867	5,425,503	6,093,826	7,894,475	10,186,339	12,566,447	14,415,685	15,084,792	15,050,333	
5.	Interest Rate (First Day of Reporting Business Month)	1.58%	1.46%	1.62%	1.86%	1.85%	1.86%	1.98%	2.45%	2.45%	2.45%	2.70%	2.70%	
6.	Interest Rate (First Day of Subsequent Business Month)	1.46%	1.62%	1.86%	1.85%	1.86%	1.98%	2.45%	2.45%	2.45%	2.70%	2.70%	2.70%	
7.	Total of Beginning & Ending Interest Rates (Lines 5 + 6) [1]	3.04%	3.08%	3.48%	3.71%	3.71%	3.84%	4.43%	4.90%	4.90%	5.15%	5.40%	5.40%	
8.	Average Interest Rate (Line 7 x 1/2) [1]	1.520%	1.540%	1.740%	1.855%	1.855%	1.920%	2.215%	2.450%	2.450%	2.575%	2.700%	2.700%	
9.	Monthly Average Interest Rate (Line 8 x 1/12) [1]	0.127%	0.128%	0.145%	0.155%	0.155%	0.160%	0.185%	0.204%	0.204%	0.215%	0.225%	0.225%	
10.	Interest Provision for the Month (Line 4 x Line 9)	$9,356	$8,341	$8,197	$8,382	$8,410	$9,750	$14,605	$20,780	$25,636	$30,994	$33,941	$33,863	$212,255

Form 42 - 4E

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2018 to December 2018

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 FGD Integration	$1,894,681	$4,423,789	($2,529,108)	-57.2%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0.0%
	c. SO_2 Emissions Allowances	(98)	9,151	(9,249)	-101.1%
	d. Big Bend Units 1 & 2 FGD	570,804	2,200,000	(1,629,196)	-74.1%
	e. Big Bend PM Minimization and Monitoring	406,562	611,283	(204,721)	-33.5%
	f. Big Bend NO_x Emissions Reduction	78,693	138,956	(60,263)	-43.4%
	g. NPDES Annual Surveillance Fees	35,883	34,500	1,383	4.0%
	h. Gannon Thermal Discharge Study	0	0	0	0.0%
	i. Polk NO_x Emissions Reduction	5,317	19,988	(14,671)	-73.4%
	j. Bayside SCR Consumables	111,102	203,882	(92,779)	-45.5%
	k. Big Bend Unit 4 SOFA	0	37,200	(37,200)	-100.0%
	l. Big Bend Unit 1 Pre-SCR	39	37,200	(37,161)	-99.9%
	m. Big Bend Unit 2 Pre-SCR	1,450	37,200	(35,750)	-96.1%
	n. Big Bend Unit 3 Pre-SCR	3,808	37,200	(33,392)	-89.8%
	o. Clean Water Act Section 316(b) Phase II Study	74,158	321,000	(246,842)	-76.9%
	p. Arsenic Groundwater Standard Program	0	0	0	0.0%
	q. Big Bend 1 SCR	351,102	1,498,585	(1,147,483)	-76.6%
	r. Big Bend 2 SCR	361,113	1,629,977	(1,268,864)	-77.8%
	s. Big Bend 3 SCR	1,553,384	1,694,774	(141,390)	-8.3%
	t. Big Bend 4 SCR	651,145	1,061,162	(410,017)	-38.6%
	u. Mercury Air Toxics Standards	24,378	231,000	(206,622)	-89.4%
	v. Greenhouse Gas Reduction Program	95,974	93,149	2,825	3.0%
	w. Big Bend Gypsum Storage Facility	1,638,273	1,663,000	(24,727)	-1.5%
	x. CCR Rule - Phase I	38,250	0	38,250	N/A
	y. Big Bend ELG Rule Study	54,007	0	54,007	N/A
	z. CCR Rule - Phase II	4,757,238	6,125,000	(1,367,762)	-22.3%
	aa. Big Bend Unit 1 Section 316(b) Impingement Mortality	0	0	0	0.0%
	ab. Big Bend ELG Rule Compliance Program	0	0	0	0.0%
2.	Total Investment Projects - Recoverable Costs	$12,707,265	$22,107,996	($9,400,732)	-42.5%
3.	Recoverable Costs Allocated to Energy	$12,597,223	$21,752,496	($9,155,273)	-42.1%
4.	Recoverable Costs Allocated to Demand	$110,042	$355,500	($245,459)	-69.0%

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-2018-0014-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 2018 to December 2018

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 FGD Integration	452,214	273,733	291,066	358,824	331,130	187,714	0	0	0	0	0	0	1,894,681		$1,894,681
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	(34)	5	8	(16)	22	(83)	0	0	0	0	0	0	(98)		(98)
d.	Big Bend Units 1 & 2 FGD	17,413	66,376	55,024	54,100	100,066	19,825	43,000	43,000	43,000	43,000	43,000	43,000	570,804		570,804
e.	Big Bend PM Minimization and Monitoring	52,762	44,712	67,899	54,273	45,912	27,938	15,000	15,000	8,065	25,000	25,000	25,000	406,562		406,562
f.	Big Bend NO_x Emissions Reduction	37	34,122	266	2,757	78	29,434	2,000	2,000	2,000	2,000	2,000	2,000	78,693		78,693
g.	NPDES Annual Surveillance Fees	34,500	0	0	0	0	1,383	0	0	0	0	0	0	35,883	$35,883	
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	688	853	440	0	0	35	950	950	400	0	250	750	5,317		5,317
j.	Bayside SCR and Ammonia	16,454	3,210	8,560	12,325	3,210	11,843	12,500	10,000	9,000	8,000	8,000	8,000	111,102		111,102
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	39	0	0	0	0	0	0	0	0	0	39		39
m.	Big Bend Unit 2 Pre-SCR	635	0	0	815	0	0	0	0	0	0	0	0	1,450		1,450
n.	Big Bend Unit 3 Pre-SCR	0	0	0	0	3,714	94	0	0	0	0	0	0	3,808		3,808
o.	Clean Water Act Section 316(b) Phase II Study	4,499	14,303	174	21,348	75	9	0	1,250	1,250	1,250	12,500	17,500	74,158	74,158	
p.	Arsenic Groundwater Standard Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
q.	Big Bend 1 SCR	6,777	18,340	3,087	32,717	33,063	14,694	40,801	41,277	39,690	50,168	24,607	45,881	351,102		351,102
r.	Big Bend 2 SCR	4,267	6,863	6,549	54,763	9,514	7,682	45,405	45,722	47,627	60,328	24,607	47,786	361,113		361,113
s.	Big Bend 3 SCR	125,936	154,048	270,635	166,420	280,869	192,408	60,405	60,722	62,627	33,098	83,425	62,791	1,553,384		1,553,384
t.	Big Bend 4 SCR	58,197	89,093	46,317	54,593	33,834	55,218	51,866	50,754	48,532	54,882	65,836	42,023	651,145		651,145
u.	Mercury Air Toxics Standards	0	0	7,823	55	0	0	3,250	2,500	3,250	2,500	2,500	2,500	24,378		24,378
v.	Greenhouse Gas Reduction Program	2,825	0	0	0	93,149	0	0	0	0	0	0	0	95,974		95,974
w.	Big Bend Gypsum Storage Facility (East 40)	163,867	110,837	59,289	124,795	239,532	159,952	130,000	130,000	130,000	130,000	130,000	130,000	1,638,273		1,638,273
x.	CCR Rule - Phase I	(3,500)	14,103	14,033	1,844	9,875	1,895	0	0	0	0	0	0	38,250		38,250
y.	Big Bend ELG Rule Study	0	11,472	0	9,832	0	32,703	0	0	0	0	0	0	54,007		54,007
z.	CCR Rule - Phase II	937,333	1,323,990	541,927	10,095	1,500	297	0	0	0	500,000	600,000	842,097	4,757,238		4,757,238
aa.	BB Unit 1 Section 316(b) Impingement Mortality	0	0	0	0	0	0	0	0	0	0	0	0	0		0
ab.	Big Bend ELG Rule Compliance	0	0	0	0	0	0	0	0	0	0	0	0	0		0
2.	Total of O&M Activities	1,874,870	2,166,060	1,373,137	959,540	1,185,543	743,043	405,177	403,175	395,441	910,226	1,021,725	1,269,328	12,707,265	$110,042	$12,597,223
3.	Recoverable Costs Allocated to Energy	1,835,871	2,151,757	1,372,963	938,192	1,185,468	741,650	405,177	401,925	394,191	908,976	1,009,225	1,251,828	12,597,223		
4.	Recoverable Costs Allocated to Demand	38,999	14,303	174	21,348	75	1,393	0	1,250	1,250	1,250	12,500	17,500	110,042		
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)	1,835,871	2,151,757	1,372,963	938,192	1,185,468	741,650	405,177	401,925	394,191	908,976	1,009,225	1,251,828	12,597,223		
8.	Jurisdictional Demand Recoverable Costs (B)	38,999	14,303	174	21,348	75	1,393	0	1,250	1,250	1,250	12,500	17,500	110,042		
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$1,874,870	$2,166,060	$1,373,137	$959,540	$1,185,543	$743,043	$405,177	$403,175	395,441	910,226	$1,021,725	$1,269,328	$12,707,265		

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2018 to December 2018

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 FGD Integration	$960,478	$1,063,216	($102,738)	-9.7%
	b.	Big Bend Units 1 & 2 Flue Gas Conditioning	249,611	280,951	(31,340)	-11.2%
	c.	Big Bend Unit 4 Continuous Emissions Monitors	51,106	55,016	(3,910)	-7.1%
	d.	Big Bend Fuel Oil Tank No. 1 Upgrade	55,003	35,856	19,147	53.4%
	e.	Big Bend Fuel Oil Tank No. 2 Upgrade	90,462	58,969	31,493	53.4%
	f.	Big Bend Unit 1 Classifier Replacement	80,406	85,047	(4,641)	-5.5%
	g.	Big Bend Unit 2 Classifier Replacement	58,125	61,751	(3,626)	-5.9%
	h.	Big Bend Section 114 Mercury Testing Platform	8,561	9,406	(845)	-9.0%
	i.	Big Bend Units 1 & 2 FGD	6,053,972	6,674,906	(620,934)	-9.3%
	j.	Big Bend FGD Optimization and Utilization	1,554,594	1,712,875	(158,281)	-9.2%
	k.	Big Bend NO_x Emissions Reduction	499,295	562,354	(63,059)	-11.2%
	l.	Big Bend PM Minimization and Monitoring	1,809,236	1,989,614	(180,378)	-9.1%
	m.	Polk NO_x Emissions Reduction	113,291	123,356	(10,065)	-8.2%
	n.	Big Bend Unit 4 SOFA	198,216	218,523	(20,307)	-9.3%
	o.	Big Bend Unit 1 Pre-SCR	137,627	149,608	(11,981)	-8.0%
	p.	Big Bend Unit 2 Pre-SCR	130,774	142,854	(12,080)	-8.5%
	q.	Big Bend Unit 3 Pre-SCR	233,148	256,173	(23,025)	-9.0%
	r.	Big Bend Unit 1 SCR	7,960,486	8,698,396	(737,910)	-8.5%
	s.	Big Bend Unit 2 SCR	8,407,134	9,195,158	(788,024)	-8.6%
	t.	Big Bend Unit 3 SCR	6,968,976	7,628,421	(659,445)	-8.6%
	u.	Big Bend Unit 4 SCR	5,420,471	5,919,666	(499,195)	-8.4%
	v.	Big Bend FGD System Reliability	2,080,439	2,325,371	(244,932)	-10.5%
	w.	Mercury Air Toxics Standards	824,512	928,320	(103,808)	-11.2%
	x.	SO_2 Emissions Allowances	(2,601)	(3,015)	414	-13.7%
	y.	Big Bend Gypsum Storage Facility	2,073,568	2,316,204	(242,636)	-10.5%
	z.	CCR Rule - Phase I	130,505	224,233	(93,728)	-41.8%
	aa.	CCR Rule - Phase II	2,298	0	2,298	N/A
	ab.	Big Bend ELG Rule Compliance	1,410	0	1,410	N/A
	ac.	Big Bend Unit 1 Section 316(b) Impingement Mortality	38,929	0	38,929	N/A
2.		Total Investment Projects - Recoverable Costs	$46,190,032	$50,713,229	($4,523,197)	-8.9%
3.		Recoverable Costs Allocated to Energy	$45,871,425	$50,394,171	($4,522,746)	-9.0%
4.		Recoverable Costs Allocated to Demand	$318,607	$319,058	($451)	-0.1%

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-2018-0014-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2018 to December 2018

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 FGD Integration	$81,171	$80,989	$80,808	$80,626	$80,445	$80,262	$79,814	$79,634	$79,453	$79,273	$79,092	$78,911	$960,478		$960,478
	b.	Big Bend Units 1 and 2 Flue Gas Conditioning	21,372	21,270	21,168	21,066	20,965	20,863	20,737	20,636	20,535	20,434	20,333	20,232	249,611		249,611
	c.	Big Bend Unit 4 Continuous Emissions Monitors	4,344	4,330	4,314	4,300	4,285	4,271	4,246	4,232	4,218	4,203	4,189	4,174	51,106		51,106
	d.	Big Bend Fuel Oil Tank No. 1 Upgrade	2,815	2,806	2,796	2,787	2,778	2,770	6,456	6,423	6,391	6,359	6,327	6,295	55,003	$55,003	
	e.	Big Bend Fuel Oil Tank No. 2 Upgrade	4,629	4,614	4,600	4,584	4,570	4,555	10,617	10,564	10,511	10,459	10,406	10,353	90,462	90,462	
	f.	Big Bend Unit 1 Classifier Replacement	6,859	6,830	6,803	6,775	6,748	6,720	6,680	6,653	6,626	6,599	6,570	6,543	80,406		80,406
	g.	Big Bend Unit 2 Classifier Replacement	4,954	4,934	4,915	4,896	4,877	4,858	4,830	4,810	4,791	4,773	4,753	4,734	58,125		58,125
	h.	Big Bend Section 114 Mercury Testing Platform	725	722	721	719	717	716	712	709	708	706	704	702	8,561		8,561
	i.	Big Bend Units 1 & 2 FGD	514,191	512,541	510,891	509,241	507,592	505,942	503,032	501,391	499,750	498,108	496,467	494,826	6,053,972		6,053,972
	j.	Big Bend FGD Optimization and Utilization	126,787	126,722	126,673	127,106	128,669	130,581	130,379	130,544	130,973	131,514	132,054	132,592	1,554,594		1,554,594
	k.	Big Bend NO_x Emissions Reduction	42,042	41,978	41,914	41,850	41,785	41,721	41,494	41,430	41,366	41,302	41,239	41,174	499,295		499,295
	l.	Big Bend PM Minimization and Monitoring	153,110	152,726	152,343	151,960	151,576	151,193	150,342	149,960	149,579	149,197	148,816	148,434	1,809,236		1,809,236
	m.	Polk NO_x Emissions Reduction	9,607	9,579	9,551	9,524	9,496	9,467	9,414	9,386	9,358	9,331	9,303	9,275	113,291		113,291
	n.	Big Bend Unit 4 SOFA	16,766	16,725	16,685	16,645	16,604	16,565	16,471	16,431	16,391	16,351	16,311	16,271	198,216		198,216
	o.	Big Bend Unit 1 Pre-SCR	11,675	11,640	11,605	11,571	11,536	11,502	11,436	11,401	11,366	11,333	11,298	11,264	137,627		137,627
	p.	Big Bend Unit 2 Pre-SCR	11,082	11,051	11,021	10,990	10,959	10,929	10,867	10,836	10,806	10,775	10,744	10,714	130,774		130,774
	q.	Big Bend Unit 3 Pre-SCR	19,734	19,684	19,634	19,583	19,533	19,484	19,374	19,324	19,275	19,224	19,175	19,124	233,148		233,148
	r.	Big Bend Unit 1 SCR	674,992	673,045	671,098	669,150	667,203	665,256	661,467	659,530	657,592	655,655	653,717	651,781	7,960,486		7,960,486
	s.	Big Bend Unit 2 SCR	712,268	710,328	708,390	706,451	704,511	702,572	698,591	696,663	694,733	692,805	690,875	688,947	8,407,134		8,407,134
	t.	Big Bend Unit 3 SCR	590,325	588,737	587,150	585,562	583,973	582,386	579,090	577,510	575,930	574,351	572,771	571,191	6,968,976		6,968,976
	u.	Big Bend Unit 4 SCR	456,706	455,523	454,342	453,169	452,014	450,873	449,762	449,995	450,229	450,462	449,286	448,110	5,420,471		5,420,471
	v.	Big Bend FGD System Reliability	175,463	175,139	174,817	174,494	174,170	173,847	172,889	172,567	172,245	171,924	171,603	171,281	2,080,439		2,080,439
	w.	Mercury Air Toxics Standards	68,615	68,478	68,407	68,337	68,454	68,315	67,999	67,924	68,881	69,839	69,701	69,562	824,512		824,512
	x.	SO_2 Emissions Allowances (B)	(218)	(218)	(218)	(217)	(217)	(217)	(216)	(216)	(216)	(216)	(216)	(216)	(2,601)		(2,601)
	y.	Big Bend Gypsum Storage Facility	174,907	174,580	174,253	173,927	173,600	173,274	172,317	171,992	171,667	171,342	171,017	170,692	2,073,568		2,073,568
	z.	CCR Rule - Phase I	6,478	6,646	6,816	6,860	6,907	6,960	8,555	10,575	14,687	17,887	18,671	19,463	130,505	130,505	
	aa.	CCR Rule - Phase II	0	0	3	7	11	21	86	202	318	434	550	666	2,298	2,298	
	ab.	Big Bend ELG Rule Compliance	0	0	0	0	0	0	0	0	0	157	470	783	1,410	1,410	
	ac.	Big Bend Unit 1 Section 316(b) Impingement Mortality	0	0	0	0	0	0	235	1,724	4,543	7,676	10,809	13,942	38,929	38,929	
2.		Total Investment Projects - Recoverable Costs	3,891,399	3,881,399	3,871,500	3,861,963	3,853,761	3,845,686	3,837,676	3,832,830	3,832,706	3,832,257	3,827,035	3,821,820	46,190,032	$318,607	$45,871,425
3.		Recoverable Costs Allocated to Energy	3,877,477	3,867,333	3,857,285	3,847,725	3,839,495	3,831,380	3,811,727	3,803,342	3,796,256	3,789,285	3,779,802	3,770,318	45,871,425		
4.		Recoverable Costs Allocated to Demand	13,922	14,066	14,215	14,238	14,266	14,306	25,949	29,488	36,450	42,972	47,233	51,502	318,607		
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)	3,877,477	3,867,333	3,857,285	3,847,725	3,839,495	3,831,380	3,811,727	3,803,342	3,796,256	3,789,285	3,779,802	3,770,318	45,871,425		
8.		Jurisdictional Demand Recoverable Costs (D)	13,922	14,066	14,215	14,238	14,266	14,306	25,949	29,488	36,450	42,972	47,233	51,502	318,607		
9.		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$3,891,399	$3,881,399	$3,871,500	$3,861,963	$3,853,761	$3,845,686	$3,837,676	$3,832,830	$3,832,706	$3,832,257	$3,827,035	$3,821,820	$46,190,032		

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 2018 to December 2018

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 FGD 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	
	c. Retirements		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	
2.	Plant-in-Service/Depreciation Base (A)	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	
3.	Less: Accumulated Depreciation	(5,440,288)	(5,469,125)	(5,497,962)	(5,526,799)	(5,555,636)	(5,584,473)	(5,613,310)	(5,642,147)	(5,670,984)	(5,699,821)	(5,728,658)	(5,757,495)	(5,786,332)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$8,322,793	8,293,956	8,265,119	8,236,282	8,207,445	8,178,608	8,149,771	8,120,934	8,092,097	8,063,260	8,034,423	8,005,586	7,976,749	
6.	Average Net Investment		8,308,375	8,279,538	8,250,701	8,221,864	8,193,027	8,164,190	8,135,353	8,106,516	8,077,679	8,048,842	8,020,005	7,991,168	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$39,900	$39,761	$39,623	$39,484	$39,346	$39,207	$39,362	$39,223	$39,083	$38,944	$38,804	$38,665	$471,402
	b. Debt Component Grossed Up For Taxes (C)		12,434	12,391	12,348	12,305	12,262	12,218	11,615	11,574	11,533	11,492	11,451	11,409	143,032
8.	Investment Expenses														
	a. Depreciation (D)		$28,837	$28,837	$28,837	$28,837	$28,837	$28,837	$28,837	$28,837	$28,837	$28,837	$28,837	$28,837	$346,044
	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)		81,171	80,989	80,808	80,626	80,445	80,262	79,814	79,634	79,453	79,273	79,092	78,911	960,478
	a. Recoverable Costs Allocated to Energy		81,171	80,989	80,808	80,626	80,445	80,262	79,814	79,634	79,453	79,273	79,092	78,911	960,478
	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)		81,171	80,989	80,808	80,626	80,445	80,262	79,814	79,634	79,453	79,273	79,092	78,911	960,478
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)		$81,171	$80,989	$80,808	$80,626	$80,445	$80,262	$79,814	$79,634	$79,453	$79,273	$79,092	$78,911	$960,478

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.45 ($13,435,775) and 315.45 ($327,307)
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8061% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7133% x 1/12 (Jul-Dec)
(D) Applicable depreciation rates are 2.5% and 3.1%
(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 2018 to December 2018

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	
	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)	$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	(4,179,278)	(4,195,419)	(4,211,560)	(4,227,701)	(4,243,842)	(4,259,983)	(4,276,124)	(4,292,265)	(4,308,406)	(4,324,547)	(4,340,688)	(4,356,829)	(4,372,970)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$838,456	822,315	806,174	790,033	773,892	757,751	741,610	725,469	709,328	693,187	677,046	660,905	644,764	
6.	Average Net Investment		830,386	814,245	798,104	781,963	765,822	749,681	733,540	717,399	701,258	685,117	668,976	652,835	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$3,988	$3,910	$3,833	$3,755	$3,678	$3,600	$3,549	$3,471	$3,393	$3,315	$3,237	$3,159	$42,888
	b. Debt Component Grossed Up For Taxes (C)		1,243	1,219	1,194	1,170	1,146	1,122	1,047	1,024	1,001	978	955	932	13,031
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)		21,372	21,270	21,168	21,066	20,965	20,863	20,737	20,636	20,535	20,434	20,333	20,232	249,611
	a. Recoverable Costs Allocated to Energy		21,372	21,270	21,168	21,066	20,965	20,863	20,737	20,636	20,535	20,434	20,333	20,232	249,611
	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)		21,372	21,270	21,168	21,066	20,965	20,863	20,737	20,636	20,535	20,434	20,333	20,232	249,611
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)		$21,372	$21,270	$21,168	$21,066	$20,965	$20,863	$20,737	$20,636	$20,535	$20,434	$20,333	$20,232	$249,611

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($2,676,217) and 312.42 ($2,341,517)
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8061% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7133% x 1/12 (Jul-Dec)
(D) Applicable depreciation rates are 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 2018 to December 2018

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	
	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)	$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	(542,165)	(544,475)	(546,785)	(549,095)	(551,405)	(553,715)	(556,025)	(558,335)	(560,645)	(562,955)	(565,265)	(567,575)	(569,885)	
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)	$324,046	321,736	319,426	317,116	314,806	312,496	310,186	307,876	305,566	303,256	300,946	298,636	296,326	
6.	Average Net Investment		322,891	320,581	318,271	315,961	313,651	311,341	309,031	306,721	304,411	302,101	299,791	297,481	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,551	$1,540	$1,528	$1,517	$1,506	$1,495	$1,495	$1,484	$1,473	$1,462	$1,451	$1,439	$17,941
	b. Debt Component Grossed Up For Taxes (C)		483	480	476	473	469	466	441	438	435	431	428	425	5,445
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)		4,344	4,330	4,314	4,300	4,285	4,271	4,246	4,232	4,218	4,203	4,189	4,174	51,106
	a. Recoverable Costs Allocated to Energy		4,344	4,330	4,314	4,300	4,285	4,271	4,246	4,232	4,218	4,203	4,189	4,174	51,106
	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)		4,344	4,330	4,314	4,300	4,285	4,271	4,246	4,232	4,218	4,203	4,189	4,174	51,106
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)		$4,344	$4,330	$4,314	$4,300	$4,285	$4,271	$4,246	$4,232	$4,218	$4,203	$4,189	$4,174	$51,106

Notes:
(A) Applicable depreciable base for Big Bend; account 315.44
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8061% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7133% 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
Calculation of the Current Period Actual / Estimated Amount
January 2018 to December 2018

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank No. 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	
	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)	$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	(273,952)	(275,362)	(276,772)	(278,182)	(279,592)	(281,002)	(282,412)	(287,535)	(292,658)	(297,781)	(302,904)	(308,027)	(313,150)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$223,626	222,216	220,806	219,396	217,986	216,576	215,166	210,043	204,920	199,797	194,674	189,551	184,428	
6.	Average Net Investment		222,921	221,511	220,101	218,691	217,281	215,871	212,605	207,482	202,359	197,236	192,113	186,990	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,071	$1,064	$1,057	$1,050	$1,043	$1,037	$1,029	$1,004	$979	$954	$930	$905	$12,123
	b. Debt Component Grossed Up For Taxes (C)		334	332	329	327	325	323	304	296	289	282	274	267	3,682
8.	Investment Expenses														
	a. Depreciation (D)		$1,410	$1,410	$1,410	$1,410	$1,410	$1,410	$5,123	$5,123	$5,123	$5,123	$5,123	$5,123	$39,198
	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. 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)		2,815	2,806	2,796	2,787	2,778	2,770	6,456	6,423	6,391	6,359	6,327	6,295	55,003
	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		2,815	2,806	2,796	2,787	2,778	2,770	6,456	6,423	6,391	6,359	6,327	6,295	55,003
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)		2,815	2,806	2,796	2,787	2,778	2,770	6,456	6,423	6,391	6,359	6,327	6,295	55,003
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$2,815	$2,806	$2,796	$2,787	$2,778	$2,770	$6,456	$6,423	$6,391	$6,359	$6,327	$6,295	$55,003

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8061% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7133% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate through June 2018 was 3.4%; depreciation was accelerated to 12.36% as of July 2018.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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DOCKET NO. 20180007-EI
ECRC 2018 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT NO. PAR-2, DOCUMENT NO. 8,
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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2018 to December 2018

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank No. 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	
	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)	$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	(450,592)	(452,911)	(455,230)	(457,549)	(459,868)	(462,187)	(464,506)	(472,932)	(481,358)	(489,784)	(498,210)	(506,636)	(515,062)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$367,809	365,490	363,171	360,852	358,533	356,214	353,895	345,469	337,043	328,617	320,191	311,765	303,339	
6.	Average Net Investment		366,650	364,331	362,012	359,693	357,374	355,055	349,682	341,256	332,830	324,404	315,978	307,552	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,761	$1,750	$1,739	$1,727	$1,716	$1,705	$1,692	$1,651	$1,610	$1,570	$1,529	$1,488	$19,938
	b. Debt Component Grossed Up For Taxes (C)		549	545	542	538	535	531	499	487	475	463	451	439	6,054
8.	Investment Expenses														
	a. Depreciation (D)		$2,319	$2,319	$2,319	$2,319	$2,319	$2,319	$8,426	$8,426	$8,426	$8,426	$8,426	$8,426	$64,470
	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)		4,629	4,614	4,600	4,584	4,570	4,555	10,617	10,564	10,511	10,459	10,406	10,353	90,462
	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		4,629	4,614	4,600	4,584	4,570	4,555	10,617	10,564	10,511	10,459	10,406	10,353	90,462
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)		4,629	4,614	4,600	4,584	4,570	4,555	10,617	10,564	10,511	10,459	10,406	10,353	90,462
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$4,629	$4,614	$4,600	$4,584	$4,570	$4,555	$10,617	$10,564	$10,511	$10,459	$10,406	$10,353	$90,462

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8061% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7133% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate through June 2018 was 3.4%; depreciation was accelerated to 12.35% as of July 2018.
(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 2018 to December 2018

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	
	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)	$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	(921,848)	(926,236)	(930,624)	(935,012)	(939,400)	(943,788)	(948,176)	(952,564)	(956,952)	(961,340)	(965,728)	(970,116)	(974,504)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$394,409	390,021	385,633	381,245	376,857	372,469	368,081	363,693	359,305	354,917	350,529	346,141	341,753	
6.	Average Net Investment		392,215	387,827	383,439	379,051	374,663	370,275	365,887	361,499	357,111	352,723	348,335	343,947	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,884	$1,862	$1,841	$1,820	$1,799	$1,778	$1,770	$1,749	$1,728	$1,707	$1,685	$1,664	$21,287
	b. Debt Component Grossed Up For Taxes (C)		587	580	574	567	561	554	522	516	510	504	497	491	6,463
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)		6,859	6,830	6,803	6,775	6,748	6,720	6,680	6,653	6,626	6,599	6,570	6,543	80,406
	a. Recoverable Costs Allocated to Energy		6,859	6,830	6,803	6,775	6,748	6,720	6,680	6,653	6,626	6,599	6,570	6,543	80,406
	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)		6,859	6,830	6,803	6,775	6,748	6,720	6,680	6,653	6,626	6,599	6,570	6,543	80,406
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)		$6,859	$6,830	$6,803	$6,775	$6,748	$6,720	$6,680	$6,653	$6,626	$6,599	$6,570	$6,543	$80,406

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8061% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7133% x 1/12 (Jul-Dec)
(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 2018 to December 2018

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	
	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)	$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	(678,870)	(681,906)	(684,942)	(687,978)	(691,014)	(694,050)	(697,086)	(700,122)	(703,158)	(706,194)	(709,230)	(712,266)	(715,302)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$305,924	302,888	299,852	296,816	293,780	290,744	287,708	284,672	281,636	278,600	275,564	272,528	269,492	
6.	Average Net Investment		304,406	301,370	298,334	295,298	292,262	289,226	286,190	283,154	280,118	277,082	274,046	271,010	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,462	$1,447	$1,433	$1,418	$1,404	$1,389	$1,385	$1,370	$1,355	$1,341	$1,326	$1,311	$16,641
	b. Debt Component Grossed Up For Taxes (C)		456	451	446	442	437	433	409	404	400	396	391	387	5,052
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)		4,954	4,934	4,915	4,896	4,877	4,858	4,830	4,810	4,791	4,773	4,753	4,734	58,125
	a. Recoverable Costs Allocated to Energy		4,954	4,934	4,915	4,896	4,877	4,858	4,830	4,810	4,791	4,773	4,753	4,734	58,125
	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)		4,954	4,934	4,915	4,896	4,877	4,858	4,830	4,810	4,791	4,773	4,753	4,734	58,125
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)		$4,954	$4,934	$4,915	$4,896	$4,877	$4,858	$4,830	$4,810	$4,791	$4,773	$4,753	$4,734	$58,125

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8061% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7133% 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
Calculation of the Current Period Actual / Estimated Amount
January 2018 to December 2018

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	
	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)	$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	(51,907)	(52,199)	(52,491)	(52,783)	(53,075)	(53,367)	(53,659)	(53,951)	(54,243)	(54,535)	(54,827)	(55,119)	(55,411)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$68,830	68,538	68,246	67,954	67,662	67,370	67,078	66,786	66,494	66,202	65,910	65,618	65,326	
6.	Average Net Investment		68,684	68,392	68,100	67,808	67,516	67,224	66,932	66,640	66,348	66,056	65,764	65,472	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$330	$328	$327	$326	$324	$323	$324	$322	$321	$320	$318	$317	$3,880
	b. Debt Component Grossed Up For Taxes (C)		103	102	102	101	101	101	96	95	95	94	94	93	1,177
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)		725	722	721	719	717	716	712	709	708	706	704	702	8,561
	a. Recoverable Costs Allocated to Energy		725	722	721	719	717	716	712	709	708	706	704	702	8,561
	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)		725	722	721	719	717	716	712	709	708	706	704	702	8,561
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)		$725	$722	$721	$719	$717	$716	$712	$709	$708	$706	$704	$702	$8,561

Notes:
(A) Applicable depreciable base for Big Bend; account 311.40
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8061% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7133% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 2.9%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Environmental Cost Recovery Clause
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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	
	c. Retirements		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	
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	(55,074,209)	(55,336,128)	(55,598,047)	(55,859,966)	(56,121,885)	(56,383,804)	(56,645,723)	(56,907,642)	(57,169,561)	(57,431,480)	(57,693,399)	(57,955,318)	(58,217,237)	
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)	$40,181,033	39,919,114	39,657,195	39,395,276	39,133,357	38,871,438	38,609,519	38,347,600	38,085,681	37,823,762	37,561,843	37,299,924	37,038,005	
6.	Average Net Investment		40,050,073	39,788,154	39,526,235	39,264,316	39,002,397	38,740,478	38,478,559	38,216,640	37,954,721	37,692,802	37,430,883	37,168,964	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$192,334	$191,076	$189,818	$188,560	$187,303	$186,045	$186,175	$184,908	$183,641	$182,373	$181,106	$179,839	$2,233,178
	b. Debt Component Grossed Up For Taxes (C)		59,938	59,546	59,154	58,762	58,370	57,978	54,938	54,564	54,190	53,816	53,442	53,068	677,766
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)		514,191	512,541	510,891	509,241	507,592	505,942	503,032	501,391	499,750	498,108	496,467	494,826	6,053,972
	a. Recoverable Costs Allocated to Energy		514,191	512,541	510,891	509,241	507,592	505,942	503,032	501,391	499,750	498,108	496,467	494,826	6,053,972
	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)		514,191	512,541	510,891	509,241	507,592	505,942	503,032	501,391	499,750	498,108	496,467	494,826	6,053,972
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)		$514,191	$512,541	$510,891	$509,241	$507,592	$505,942	$503,032	$501,391	$499,750	$498,108	$496,467	$494,826	$6,053,972

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.46 ($94,929,061), 312.45 ($105,398) & 315.46 ($220,782)
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8061% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7133% x 1/12 (Jul-Dec)
(D) Applicable depreciation rates are 3.3%, 2.5% and 3.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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January 2018 to December 2018

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		$29,435	$7,632	$61,810	$126,316	$377,714	$71,808	$45,911	$100,000	$100,000	$100,000	$100,000	$100,000	$1,220,627
	b. Clearings to Plant		29,435	7,632	61,810	126,316	377,714	71,808	0	45,911	100,000	100,000	100,000	100,000	1,120,627
	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)	$21,739,737	$21,769,172	$21,776,804	$21,838,615	$21,964,930	$22,342,644	$22,414,453	$22,414,453	$22,460,364	$22,560,364	$22,660,364	$22,760,364	$22,860,364	
3.	Less: Accumulated Depreciation	(8,790,925)	(8,836,199)	(8,881,576)	(8,926,971)	(8,972,493)	(9,018,278)	(9,064,850)	(9,111,581)	(9,158,312)	(9,205,139)	(9,252,174)	(9,299,418)	(9,346,870)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	45,911	100,000	100,000	100,000	100,000	100,000	
5.	Net Investment (Lines 2 + 3 + 4)	$12,948,812	12,932,973	12,895,228	12,911,644	12,992,437	13,324,366	13,349,603	13,348,783	13,402,052	13,455,225	13,508,190	13,560,946	13,613,494	
6.	Average Net Investment		12,940,893	12,914,101	12,903,436	12,952,040	13,158,402	13,336,985	13,349,193	13,375,417	13,428,638	13,481,707	13,534,568	13,587,220	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$62,146	$62,018	$61,967	$62,200	$63,191	$64,049	$64,589	$64,716	$64,973	$65,230	$65,486	$65,741	$766,306
	b. Debt Component Grossed Up For Taxes (C)		19,367	19,327	19,311	19,384	19,693	19,960	19,059	19,097	19,173	19,249	19,324	19,399	232,343
8.	Investment Expenses														
	a. Depreciation (D)		$45,274	$45,377	$45,395	$45,522	$45,785	$46,572	$46,731	$46,731	$46,827	$47,035	$47,244	$47,452	$555,945
	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)		126,787	126,722	126,673	127,106	128,669	130,581	130,379	130,544	130,973	131,514	132,054	132,592	1,554,594
	a. Recoverable Costs Allocated to Energy		126,787	126,722	126,673	127,106	128,669	130,581	130,379	130,544	130,973	131,514	132,054	132,592	1,554,594
	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)		126,787	126,722	126,673	127,106	128,669	130,581	130,379	130,544	130,973	131,514	132,054	132,592	1,554,594
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)		$126,787	$126,722	$126,673	$127,106	$128,669	$130,581	$130,379	$130,544	$130,973	$131,514	$132,054	$132,592	$1,554,594

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.45 ($22,784,292),311.45 ($39,818) and 316.40 ($36,254)
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8061% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7133% x 1/12 (Jul-Dec)
(D) Applicable depreciation rates are 2.5%, 2.0% and 4.2%
(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 2018 to December 2018

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	
	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)	$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	1,871,979	1,861,795	1,851,611	1,841,427	1,831,243	1,821,059	1,810,875	1,800,691	1,790,507	1,780,323	1,770,139	1,759,955	1,749,771	
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)	$5,062,831	5,052,647	5,042,463	5,032,279	5,022,095	5,011,911	5,001,727	4,991,543	4,981,359	4,971,175	4,960,991	4,950,807	4,940,623	
6.	Average Net Investment		5,057,739	5,047,555	5,037,371	5,027,187	5,017,003	5,006,819	4,996,635	4,986,451	4,976,267	4,966,083	4,955,899	4,945,715	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$24,289	$24,240	$24,191	$24,142	$24,093	$24,044	$24,176	$24,127	$24,077	$24,028	$23,979	$23,929	$289,315
	b. Debt Component Grossed Up For Taxes (C)		7,569	7,554	7,539	7,524	7,508	7,493	7,134	7,119	7,105	7,090	7,076	7,061	87,772
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)		42,042	41,978	41,914	41,850	41,785	41,721	41,494	41,430	41,366	41,302	41,239	41,174	499,295
	a. Recoverable Costs Allocated to Energy		42,042	41,978	41,914	41,850	41,785	41,721	41,494	41,430	41,366	41,302	41,239	41,174	499,295
	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)		42,042	41,978	41,914	41,850	41,785	41,721	41,494	41,430	41,366	41,302	41,239	41,174	499,295
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)		$42,042	$41,978	$41,914	$41,850	$41,785	$41,721	$41,494	$41,430	$41,366	$41,302	$41,239	$41,174	$499,295

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 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8061% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7133% x 1/12 (Jul-Dec)
(D) Applicable depreciation rates are 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 2018 to December 2018

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		($24)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($24)
	b. Clearings to Plant		(24)	0	0	0	0	0	0	0	0	0	0	0	(24)
	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	
2.	Plant-in-Service/Depreciation Base (A)	$19,757,774	$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	(5,083,858)	(5,144,730)	(5,205,602)	(5,266,474)	(5,327,346)	(5,388,218)	(5,449,090)	(5,509,962)	(5,570,834)	(5,631,706)	(5,692,578)	(5,753,450)	(5,814,322)	
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)	$14,673,916	14,613,020	14,552,148	14,491,276	14,430,404	14,369,532	14,308,660	14,247,788	14,186,916	14,126,044	14,065,172	14,004,300	13,943,428	
6.	Average Net Investment		14,643,468	14,582,584	14,521,712	14,460,840	14,399,968	14,339,096	14,278,224	14,217,352	14,156,480	14,095,608	14,034,736	13,973,864	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$70,323	$70,030	$69,738	$69,446	$69,153	$68,861	$69,084	$68,789	$68,495	$68,200	$67,906	$67,611	$827,636
	b. Debt Component Grossed Up For Taxes (C)		21,915	21,824	21,733	21,642	21,551	21,460	20,386	20,299	20,212	20,125	20,038	19,951	251,136
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)		153,110	152,726	152,343	151,960	151,576	151,193	150,342	149,960	149,579	149,197	148,816	148,434	1,809,236
	a. Recoverable Costs Allocated to Energy		153,110	152,726	152,343	151,960	151,576	151,193	150,342	149,960	149,579	149,197	148,816	148,434	1,809,236
	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)		153,110	152,726	152,343	151,960	151,576	151,193	150,342	149,960	149,579	149,197	148,816	148,434	1,809,236
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)		$153,110	$152,726	$152,343	$151,960	$151,576	$151,193	$150,342	$149,960	$149,579	$149,197	$148,816	$148,434	$1,809,236

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 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8061% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7133% x 1/12 (Jul-Dec)
(D) Applicable depreciation rates are 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 2018 to December 2018

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	
	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)	$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	(736,410)	(740,834)	(745,258)	(749,682)	(754,106)	(758,530)	(762,954)	(767,378)	(771,802)	(776,226)	(780,650)	(785,074)	(789,498)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$825,063	820,639	816,215	811,791	807,367	802,943	798,519	794,095	789,671	785,247	780,823	776,399	771,975	
6.	Average Net Investment		822,851	818,427	814,003	809,579	805,155	800,731	796,307	791,883	787,459	783,035	778,611	774,187	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$3,952	$3,930	$3,909	$3,888	$3,867	$3,845	$3,853	$3,831	$3,810	$3,789	$3,767	$3,746	$46,187
	b. Debt Component Grossed Up For Taxes (C)		1,231	1,225	1,218	1,212	1,205	1,198	1,137	1,131	1,124	1,118	1,112	1,105	14,016
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)		9,607	9,579	9,551	9,524	9,496	9,467	9,414	9,386	9,358	9,331	9,303	9,275	113,291
	a. Recoverable Costs Allocated to Energy		9,607	9,579	9,551	9,524	9,496	9,467	9,414	9,386	9,358	9,331	9,303	9,275	113,291
	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)		9,607	9,579	9,551	9,524	9,496	9,467	9,414	9,386	9,358	9,331	9,303	9,275	113,291
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)		$9,607	$9,579	$9,551	$9,524	$9,496	$9,467	$9,414	$9,386	$9,358	$9,331	$9,303	$9,275	$113,291

Notes:
(A) Applicable depreciable base for Polk; account 342.81
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8061% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7133% x 1/12 (Jul-Dec)
(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 2018 to December 2018

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	
	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)	$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	(909,434)	(915,831)	(922,228)	(928,625)	(935,022)	(941,419)	(947,816)	(954,213)	(960,610)	(967,007)	(973,404)	(979,801)	(986,198)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,649,296	1,642,899	1,636,502	1,630,105	1,623,708	1,617,311	1,610,914	1,604,517	1,598,120	1,591,723	1,585,326	1,578,929	1,572,532	
6.	Average Net Investment		1,646,098	1,639,701	1,633,304	1,626,907	1,620,510	1,614,113	1,607,716	1,601,319	1,594,922	1,588,525	1,582,128	1,575,731	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$7,905	$7,874	$7,844	$7,813	$7,782	$7,752	$7,779	$7,748	$7,717	$7,686	$7,655	$7,624	$93,179
	b. Debt Component Grossed Up For Taxes (C)		2,464	2,454	2,444	2,435	2,425	2,416	2,295	2,286	2,277	2,268	2,259	2,250	28,273
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)		16,766	16,725	16,685	16,645	16,604	16,565	16,471	16,431	16,391	16,351	16,311	16,271	198,216
	a. Recoverable Costs Allocated to Energy		16,766	16,725	16,685	16,645	16,604	16,565	16,471	16,431	16,391	16,351	16,311	16,271	198,216
	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)		16,766	16,725	16,685	16,645	16,604	16,565	16,471	16,431	16,391	16,351	16,311	16,271	198,216
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)		$16,766	$16,725	$16,685	$16,645	$16,604	$16,565	$16,471	$16,431	$16,391	$16,351	$16,311	$16,271	$198,216

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8061% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7133% 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
Calculation of the Current Period Actual / Estimated Amount
January 2018 to December 2018

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	
	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)	$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	(665,629)	(671,126)	(676,623)	(682,120)	(687,617)	(693,114)	(698,611)	(704,108)	(709,605)	(715,102)	(720,599)	(726,096)	(731,593)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$983,492	977,995	972,498	967,001	961,504	956,007	950,510	945,013	939,516	934,019	928,522	923,025	917,528	
6.	Average Net Investment		980,744	975,247	969,750	964,253	958,756	953,259	947,762	942,265	936,768	931,271	925,774	920,277	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$4,710	$4,683	$4,657	$4,631	$4,604	$4,578	$4,586	$4,559	$4,532	$4,506	$4,479	$4,453	$54,978
	b. Debt Component Grossed Up For Taxes (C)		1,468	1,460	1,451	1,443	1,435	1,427	1,353	1,345	1,337	1,330	1,322	1,314	16,685
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)		11,675	11,640	11,605	11,571	11,536	11,502	11,436	11,401	11,366	11,333	11,298	11,264	137,627
	a. Recoverable Costs Allocated to Energy		11,675	11,640	11,605	11,571	11,536	11,502	11,436	11,401	11,366	11,333	11,298	11,264	137,627
	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)		11,675	11,640	11,605	11,571	11,536	11,502	11,436	11,401	11,366	11,333	11,298	11,264	137,627
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)		$11,675	$11,640	$11,605	$11,571	$11,536	$11,502	$11,436	$11,401	$11,366	$11,333	$11,298	$11,264	$137,627

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8061% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7133% x 1/12 (Jul-Dec)
(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 2018 to December 2018

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	
	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)	$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	(594,320)	(599,197)	(604,074)	(608,951)	(613,828)	(618,705)	(623,582)	(628,459)	(633,336)	(638,213)	(643,090)	(647,967)	(652,844)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$987,567	982,690	977,813	972,936	968,059	963,182	958,305	953,428	948,551	943,674	938,797	933,920	929,043	
6.	Average Net Investment		985,129	980,252	975,375	970,498	965,621	960,744	955,867	950,990	946,113	941,236	936,359	931,482	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$4,731	$4,707	$4,684	$4,661	$4,637	$4,614	$4,625	$4,601	$4,578	$4,554	$4,530	$4,507	$55,429
	b. Debt Component Grossed Up For Taxes (C)		1,474	1,467	1,460	1,452	1,445	1,438	1,365	1,358	1,351	1,344	1,337	1,330	16,821
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)		11,082	11,051	11,021	10,990	10,959	10,929	10,867	10,836	10,806	10,775	10,744	10,714	130,774
	a. Recoverable Costs Allocated to Energy		11,082	11,051	11,021	10,990	10,959	10,929	10,867	10,836	10,806	10,775	10,744	10,714	130,774
	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)		11,082	11,051	11,021	10,990	10,959	10,929	10,867	10,836	10,806	10,775	10,744	10,714	130,774
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)		$11,082	$11,051	$11,021	$10,990	$10,959	$10,929	$10,867	$10,836	$10,806	$10,775	$10,744	$10,714	$130,774

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8061% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7133% x 1/12 (Jul-Dec)
(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 2018 to December 2018

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	
	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)	$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	(832,202)	(840,155)	(848,108)	(856,061)	(864,014)	(871,967)	(879,920)	(887,873)	(895,826)	(903,779)	(911,732)	(919,685)	(927,638)	
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)	$1,874,305	1,866,352	1,858,399	1,850,446	1,842,493	1,834,540	1,826,587	1,818,634	1,810,681	1,802,728	1,794,775	1,786,822	1,778,869	
6.	Average Net Investment		1,870,329	1,862,376	1,854,423	1,846,470	1,838,517	1,830,564	1,822,611	1,814,658	1,806,705	1,798,752	1,790,799	1,782,846	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$8,982	$8,944	$8,906	$8,867	$8,829	$8,791	$8,819	$8,780	$8,742	$8,703	$8,665	$8,626	$105,654
	b. Debt Component Grossed Up For Taxes (C)		2,799	2,787	2,775	2,763	2,751	2,740	2,602	2,591	2,580	2,568	2,557	2,545	32,058
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)		19,734	19,684	19,634	19,583	19,533	19,484	19,374	19,324	19,275	19,224	19,175	19,124	233,148
	a. Recoverable Costs Allocated to Energy		19,734	19,684	19,634	19,583	19,533	19,484	19,374	19,324	19,275	19,224	19,175	19,124	233,148
	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)		19,734	19,684	19,634	19,583	19,533	19,484	19,374	19,324	19,275	19,224	19,175	19,124	233,148
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)		$19,734	$19,684	$19,634	$19,583	$19,533	$19,484	$19,374	$19,324	$19,275	$19,224	$19,175	$19,124	$233,148

Notes:
(A) Applicable depreciable base for Big Bend; account 312.43 ($1,995,677) and 315.43 ($710,830)
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8061% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7133% 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

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2018 to December 2018

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	
	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)	$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	(28,849,638)	(29,158,804)	(29,467,970)	(29,777,136)	(30,086,302)	(30,395,468)	(30,704,634)	(31,013,800)	(31,322,966)	(31,632,132)	(31,941,298)	(32,250,464)	(32,559,630)	
4.	CWIP - Non-Interest Bearing	1,362,824	1,362,824	1,362,824	1,362,824	1,362,824	1,362,824	1,362,824	1,362,824	1,362,824	1,362,824	1,362,824	1,362,824	1,362,824	
5.	Net Investment (Lines 2 + 3 + 4)	$58,232,288	57,923,122	57,613,956	57,304,790	56,995,624	56,686,458	56,377,292	56,068,126	55,758,960	55,449,794	55,140,628	54,831,462	54,522,296	
6.	Average Net Investment		58,077,705	57,768,539	57,459,373	57,150,207	56,841,041	56,531,875	56,222,709	55,913,543	55,604,377	55,295,211	54,986,045	54,676,879	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$278,908	$277,424	$275,939	$274,454	$272,970	$271,485	$272,029	$270,533	$269,037	$267,541	$266,045	$264,550	$3,260,915
	b. Debt Component Grossed Up For Taxes (C)		86,918	86,455	85,993	85,530	85,067	84,605	80,272	79,831	79,389	78,948	78,506	78,065	989,579
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)		674,992	673,045	671,098	669,150	667,203	665,256	661,467	659,530	657,592	655,655	653,717	651,781	7,960,486
	a. Recoverable Costs Allocated to Energy		674,992	673,045	671,098	669,150	667,203	665,256	661,467	659,530	657,592	655,655	653,717	651,781	7,960,486
	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)		674,992	673,045	671,098	669,150	667,203	665,256	661,467	659,530	657,592	655,655	653,717	651,781	7,960,486
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)		$674,992	$673,045	$671,098	$669,150	$667,203	$665,256	$661,467	$659,530	$657,592	$655,655	$653,717	$651,781	$7,960,486

Notes:
(A) Applicable depreciable base for Big Bend; account 311.51 ($22,278,982), 312.51 ($48,529,672), 315.51 ($14,063,245), and 316.51 ($847,203).
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8061% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7133% 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

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2018 to December 2018

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	
	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)	$95,175,309	$95,175,309	$95,175,309	$95,175,309	$95,175,309	$95,175,309	$95,175,309	$95,175,309	$95,175,309	$95,175,309	$95,175,309	$95,175,309	$95,175,309	
3.	Less: Accumulated Depreciation	(30,814,532)	(31,122,366)	(31,430,200)	(31,738,034)	(32,045,868)	(32,353,702)	(32,661,536)	(32,969,370)	(33,277,204)	(33,585,038)	(33,892,872)	(34,200,706)	(34,508,540)	
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)	$64,360,777	64,052,943	63,745,109	63,437,275	63,129,441	62,821,607	62,513,773	62,205,939	61,898,105	61,590,271	61,282,437	60,974,603	60,666,769	
6.	Average Net Investment		64,206,860	63,899,026	63,591,192	63,283,358	62,975,524	62,667,690	62,359,856	62,052,022	61,744,188	61,436,354	61,128,520	60,820,686	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$308,343	$306,864	$305,386	$303,908	$302,429	$300,951	$301,723	$300,234	$298,744	$297,255	$295,765	$294,276	$3,615,878
	b. Debt Component Grossed Up For Taxes (C)		96,091	95,630	95,170	94,709	94,248	93,787	89,034	88,595	88,155	87,716	87,276	86,837	1,097,248
8.	Investment Expenses														
	a. Depreciation (D)		$307,834	$307,834	$307,834	$307,834	$307,834	$307,834	$307,834	$307,834	$307,834	$307,834	$307,834	$307,834	$3,694,008
	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)		712,268	710,328	708,390	706,451	704,511	702,572	698,591	696,663	694,733	692,805	690,875	688,947	8,407,134
	a. Recoverable Costs Allocated to Energy		712,268	710,328	708,390	706,451	704,511	702,572	698,591	696,663	694,733	692,805	690,875	688,947	8,407,134
	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)		712,268	710,328	708,390	706,451	704,511	702,572	698,591	696,663	694,733	692,805	690,875	688,947	8,407,134
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)		$712,268	$710,328	$708,390	$706,451	$704,511	$702,572	$698,591	$696,663	$694,733	$692,805	$690,875	$688,947	$8,407,134

Notes:
(A) Applicable depreciable base for Big Bend; account 311.52 ($25,208,869), 312.52 ($53,093,397), 315.52 ($15,914,427), and 316.52 ($958,616).
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8061% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7133% 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

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2018 to December 2018

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	
	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)	$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	(27,938,697)	(28,190,771)	(28,442,845)	(28,694,919)	(28,946,993)	(29,199,067)	(29,451,141)	(29,703,215)	(29,955,289)	(30,207,363)	(30,459,437)	(30,711,511)	(30,963,585)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$53,825,905	53,573,831	53,321,757	53,069,683	52,817,609	52,565,535	52,313,461	52,061,387	51,809,313	51,557,239	51,305,165	51,053,091	50,801,017	
6.	Average Net Investment		53,699,868	53,447,794	53,195,720	52,943,646	52,691,572	52,439,498	52,187,424	51,935,350	51,683,276	51,431,202	51,179,128	50,927,054	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$257,885	$256,674	$255,464	$254,253	$253,042	$251,832	$252,505	$251,285	$250,065	$248,846	$247,626	$246,406	$3,025,883
	b. Debt Component Grossed Up For Taxes (C)		80,366	79,989	79,612	79,235	78,857	78,480	74,511	74,151	73,791	73,431	73,071	72,711	918,205
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)		590,325	588,737	587,150	585,562	583,973	582,386	579,090	577,510	575,930	574,351	572,771	571,191	6,968,976
	a. Recoverable Costs Allocated to Energy		590,325	588,737	587,150	585,562	583,973	582,386	579,090	577,510	575,930	574,351	572,771	571,191	6,968,976
	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)		590,325	588,737	587,150	585,562	583,973	582,386	579,090	577,510	575,930	574,351	572,771	571,191	6,968,976
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)		$590,325	$588,737	$587,150	$585,562	$583,973	$582,386	$579,090	$577,510	$575,930	$574,351	$572,771	$571,191	$6,968,976

Notes:
(A) Applicable depreciable base for Big Bend; account 311.53 ($21,689,422), 312.53 ($45,559,543), 315.53 ($13,690,954), and 316.53 ($824,684).
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8061% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7133% x 1/12 (Jul-Dec)
(D) Applicable depreciation rates are 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
Calculation of the Current Period Actual / Estimated Amount
January 2018 to December 2018

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	($34)	$431	$2,699	$5,941	$7,263	$450,000	$0	$450,000	$0	$0	$0	$916,300
	b. Clearings to Plant		0	(34)	0	0	0	0	0	0	0	0	0	0	(34)
	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)	$65,312,615	$65,312,615	$65,312,581	$65,312,581	$65,312,581	$65,312,581	$65,312,581	$65,312,581	$65,312,581	$65,312,581	$65,312,581	$65,312,581	$65,312,581	
3.	Less: Accumulated Depreciation	(22,513,773)	(22,701,483)	(22,889,193)	(23,076,903)	(23,264,613)	(23,452,323)	(23,640,033)	(23,827,743)	(24,015,453)	(24,203,163)	(24,390,873)	(24,578,583)	(24,766,293)	
4.	CWIP - Non-Interest Bearing	0	0	0	431	3,131	9,071	16,335	466,335	466,335	916,335	916,335	916,335	916,335	
5.	Net Investment (Lines 2 + 3 + 4)	$42,798,842	42,611,132	42,423,388	42,236,109	42,051,098	41,869,329	41,688,882	41,951,172	41,763,462	42,025,752	41,838,042	41,650,332	41,462,622	
6.	Average Net Investment		42,704,987	42,517,260	42,329,748	42,143,603	41,960,213	41,779,105	41,820,027	41,857,317	41,894,607	41,931,897	41,744,187	41,556,477	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$205,084	$204,182	$203,282	$202,388	$201,507	$200,637	$202,343	$202,523	$202,704	$202,884	$201,976	$201,068	$2,430,578
	b. Debt Component Grossed Up For Taxes (C)		63,912	63,631	63,350	63,071	62,797	62,526	59,709	59,762	59,815	59,868	59,600	59,332	737,373
8.	Investment Expenses														
	a. Depreciation (D)		$187,710	$187,710	$187,710	$187,710	$187,710	$187,710	$187,710	$187,710	$187,710	$187,710	$187,710	$187,710	$2,252,520
	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)		456,706	455,523	454,342	453,169	452,014	450,873	449,762	449,995	450,229	450,462	449,286	448,110	5,420,471
	a. Recoverable Costs Allocated to Energy		456,706	455,523	454,342	453,169	452,014	450,873	449,762	449,995	450,229	450,462	449,286	448,110	5,420,471
	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)		456,706	455,523	454,342	453,169	452,014	450,873	449,762	449,995	450,229	450,462	449,286	448,110	5,420,471
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)		$456,706	$455,523	$454,342	$453,169	$452,014	$450,873	$449,762	$449,995	$450,229	$450,462	$449,286	$448,110	$5,420,471

Notes:
(A) Applicable depreciable base for Big Bend; account 311.54 ($16,857,250), 312.54 ($36,567,266), 315.54 ($10,642,027), 316.54 ($687,934), and 315.40 ($558,103)
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8061% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7133% x 1/12 (Jul-Dec)
(D) Applicable depreciation rates are 2.4%, 3.8%, 3.9%, 3.3%, 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 2018 to December 2018

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	
	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)	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	
3.	Less: Accumulated Depreciation	(4,600,662)	(4,651,971)	(4,703,280)	(4,754,589)	(4,805,898)	(4,857,207)	(4,908,516)	(4,959,825)	(5,011,134)	(5,062,443)	(5,113,752)	(5,165,061)	(5,216,370)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$19,736,045	19,684,736	19,633,427	19,582,118	19,530,809	19,479,500	19,428,191	19,376,882	19,325,573	19,274,264	19,222,955	19,171,646	19,120,337	
6.	Average Net Investment		19,710,391	19,659,082	19,607,773	19,556,464	19,505,155	19,453,846	19,402,537	19,351,228	19,299,919	19,248,610	19,197,301	19,145,992	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$94,656	$94,409	$94,163	$93,917	$93,670	$93,424	$93,878	$93,629	$93,381	$93,133	$92,885	$92,636	$1,123,781
	b. Debt Component Grossed Up For Taxes (C)		29,498	29,421	29,345	29,268	29,191	29,114	27,702	27,629	27,555	27,482	27,409	27,336	340,950
8.	Investment Expenses														
	a. Depreciation (D)		$51,309	$51,309	$51,309	$51,309	$51,309	$51,309	$51,309	$51,309	$51,309	$51,309	$51,309	$51,309	$615,708
	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)		175,463	175,139	174,817	174,494	174,170	173,847	172,889	172,567	172,245	171,924	171,603	171,281	2,080,439
	a. Recoverable Costs Allocated to Energy		175,463	175,139	174,817	174,494	174,170	173,847	172,889	172,567	172,245	171,924	171,603	171,281	2,080,439
	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)		175,463	175,139	174,817	174,494	174,170	173,847	172,889	172,567	172,245	171,924	171,603	171,281	2,080,439
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)		$175,463	$175,139	$174,817	$174,494	$174,170	$173,847	$172,889	$172,567	$172,245	$171,924	$171,603	$171,281	$2,080,439

Notes:
(A) Applicable depreciable base for Big Bend; account 312.45 ($22,880,499) and 312.44 ($1,456,209).
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8061% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7133% 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

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DOCKET NO. 20180007-EI
ECRC 2018 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT NO. PAR-2, DOCUMENT NO. 8,
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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2018 to December 2018

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	$21,483	$0	$0	$0	$20,095	$0	$350,000	$0	$0	$0	$391,578
	b. Clearings to Plant		0	0	0	21,483	0	0	0	0	0	0	0	20,095	41,578
	c. Retirements		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	
2.	Plant-in-Service/Depreciation Base (A)	$8,586,395	$8,586,395	$8,586,395	$8,586,395	$8,607,879	$8,607,879	$8,607,879	$8,607,879	$8,607,879	$8,607,879	$8,607,879	$8,607,879	$8,627,974	
3.	Less: Accumulated Depreciation	(1,155,720)	(1,177,599)	(1,199,478)	(1,221,357)	(1,243,236)	(1,265,371)	(1,287,506)	(1,309,641)	(1,331,776)	(1,353,911)	(1,376,046)	(1,398,181)	(1,420,316)	
4.	CWIP - Non-Interest Bearing	0	0	0	21,483	0	0	0	20,095	20,095	370,095	370,095	370,095	350,000	
5.	Net Investment (Lines 2 + 3 + 4)	$7,430,675	7,408,796	7,386,917	7,386,522	7,364,643	7,342,508	7,320,373	7,318,333	7,296,198	7,624,063	7,601,928	7,579,793	7,557,658	
6.	Average Net Investment		7,419,736	7,397,857	7,386,720	7,375,582	7,353,575	7,331,440	7,319,353	7,307,265	7,460,130	7,612,995	7,590,860	7,568,725	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$35,632	$35,527	$35,473	$35,420	$35,314	$35,208	$35,414	$35,356	$36,095	$36,835	$36,728	$36,621	$429,623
	b. Debt Component Grossed Up For Taxes (C)		11,104	11,072	11,055	11,038	11,005	10,972	10,450	10,433	10,651	10,869	10,838	10,806	130,293
8.	Investment Expenses														
	a. Depreciation (D)		$21,879	$21,879	$21,879	$21,879	$22,135	$22,135	$22,135	$22,135	$22,135	$22,135	$22,135	$22,135	$264,596
	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. 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)		68,615	68,478	68,407	68,337	68,454	68,315	67,999	67,924	68,881	69,839	69,701	69,562	824,512
	a. Recoverable Costs Allocated to Energy		68,615	68,478	68,407	68,337	68,454	68,315	67,999	67,924	68,881	69,839	69,701	69,562	824,512
	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)		68,615	68,478	68,407	68,337	68,454	68,315	67,999	67,924	68,881	69,839	69,701	69,562	824,512
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)		$68,615	$68,478	$68,407	$68,337	$68,454	$68,315	$67,999	$67,924	$68,881	$69,839	$69,701	$69,562	$824,512

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) and 315.46 ($50,784), 311.40 ($13,216), 345.81 ($22,327), 312.54 ($210,295) and 395.00 ($21,483)
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8061% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7133% 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

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2018 to December 2018

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	97	0	0	0	0	0	0	97
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	(34,513)	(34,472)	(34,472)	(34,472)	(34,440)	(34,440)	(34,440)	(34,440)	(34,440)	(34,440)	(34,440)	(34,440)	(34,440)	
3.	Total Working Capital Balance	($34,513)	(34,472)	(34,472)	(34,472)	(34,440)	(34,440)	(34,440)	(34,440)	(34,440)	(34,440)	(34,440)	(34,440)	(34,440)	
4.	Average Net Working Capital Balance		(34,493)	(34,472)	(34,472)	(34,456)	(34,440)	(34,440)	(34,440)	(34,440)	(34,440)	(34,440)	(34,440)	(34,440)	
5.	Return on Average Net Working Capital Balance														
	a. Equity Component Grossed Up For Taxes (A)		($166)	($166)	($166)	($165)	($165)	($165)	($167)	($167)	($167)	($167)	($167)	($167)	($1,995)
	b. Debt Component Grossed Up For Taxes (B)		(52)	(52)	(52)	(52)	(52)	(52)	(49)	(49)	(49)	(49)	(49)	(49)	(606)
6.	Total Return Component		(218)	(218)	(218)	(217)	(217)	(217)	(216)	(216)	(216)	(216)	(216)	(216)	(2,601)
7.	Expenses:														
	a. Gains		0	0	0	0	0	(97)	0	0	0	0	0	0	(97)
	b. Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. SO_2 Allowance Expense		(34)	5	8	(16)	22	14	(50)	12	12	(33)	12	12	(36)
8.	Net Expenses (D)		(34)	5	8	(16)	22	(83)	(50)	12	12	(33)	12	12	(133)
9.	Total System Recoverable Expenses (Lines 6 + 8)		(252)	(213)	(210)	(233)	(195)	(300)	(266)	(204)	(204)	(249)	(204)	(204)	(2,734)
	a. Recoverable Costs Allocated to Energy		(252)	(213)	(210)	(233)	(195)	(300)	(266)	(204)	(204)	(249)	(204)	(204)	(2,734)
	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)		(252)	(213)	(210)	(233)	(195)	(300)	(266)	(204)	(204)	(249)	(204)	(204)	(2,734)
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)		($252)	($213)	($210)	($233)	($195)	($300)	($266)	($204)	($204)	($249)	($204)	($204)	($2,734)

Notes:
(A) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8061% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(B) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7133% 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
Calculation of the Current Period Actual / Estimated Amount
January 2018 to December 2018

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	
	c. Retirements		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	
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	(1,909,779)	(1,961,658)	(2,013,537)	(2,065,416)	(2,117,295)	(2,169,174)	(2,221,053)	(2,272,932)	(2,324,811)	(2,376,690)	(2,428,569)	(2,480,448)	(2,532,327)	
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)	$19,557,580	19,505,701	19,453,822	19,401,943	19,350,064	19,298,185	19,246,306	19,194,427	19,142,548	19,090,669	19,038,790	18,986,911	18,935,032	
6.	Average Net Investment		19,531,641	19,479,762	19,427,883	19,376,004	19,324,125	19,272,246	19,220,367	19,168,488	19,116,609	19,064,730	19,012,851	18,960,972	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$93,797	$93,548	$93,299	$93,050	$92,801	$92,552	$92,996	$92,745	$92,494	$92,243	$91,992	$91,741	$1,113,258
	b. Debt Component Grossed Up For Taxes (C)		29,231	29,153	29,075	28,998	28,920	28,843	27,442	27,368	27,294	27,220	27,146	27,072	337,762
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)		174,907	174,580	174,253	173,927	173,600	173,274	172,317	171,992	171,667	171,342	171,017	170,692	2,073,568
	a. Recoverable Costs Allocated to Energy		174,907	174,580	174,253	173,927	173,600	173,274	172,317	171,992	171,667	171,342	171,017	170,692	2,073,568
	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)		174,907	174,580	174,253	173,927	173,600	173,274	172,317	171,992	171,667	171,342	171,017	170,692	2,073,568
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)		$174,907	$174,580	$174,253	$173,927	$173,600	$173,274	$172,317	$171,992	$171,667	$171,342	$171,017	$170,692	$2,073,568

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.40
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8061% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7133% x 1/12 (Jul-Dec)
(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 2018 to December 2018

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Coal Combustion Residual (CCR Rule) -Phase I
(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		$5,637	$51,314	$6,003	$11,226	$6,964	$13,389	$507,799	$140,200	$505,323	$121,700	$49,700	$190,184	$1,609,440
	b. Clearings to Plant		0	0	0	0	0	0	0	842,772	505,323	111,700	29,700	220,184	1,709,679
	c. Retirements		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	
2.	Plant-in-Service/Depreciation Base (A)	$668,735	$668,735	$668,735	$668,735	$668,735	$668,735	$668,735	$668,735	$1,511,507	$2,016,830	$2,128,530	$2,158,230	$2,378,414	
3.	Less: Accumulated Depreciation	(8,097)	(9,769)	(11,441)	(13,113)	(14,785)	(16,457)	(18,129)	(19,801)	(21,473)	(25,252)	(30,294)	(35,615)	(41,011)	
4.	CWIP - Non-Interest Bearing	100,239	105,876	157,191	163,194	174,420	181,384	194,773	702,572	0	0	10,000	30,000	0	
5.	Net Investment (Lines 2 + 3 + 4)	$760,877	764,842	814,485	818,816	828,370	833,662	845,379	1,351,506	1,490,034	1,991,578	2,108,236	2,152,615	2,337,403	
6.	Average Net Investment		762,860	789,663	816,650	823,593	831,016	839,520	1,098,442	1,420,770	1,740,806	2,049,907	2,130,425	2,245,009	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$3,664	$3,792	$3,922	$3,955	$3,991	$4,032	$5,315	$6,874	$8,423	$9,918	$10,308	$10,862	$75,056
	b. Debt Component Grossed Up For Taxes (C)		1,142	1,182	1,222	1,233	1,244	1,256	1,568	2,029	2,485	2,927	3,042	3,205	22,535
8.	Investment Expenses														
	a. Depreciation (D)		$1,672	$1,672	$1,672	$1,672	$1,672	$1,672	$1,672	$1,672	$3,779	$5,042	$5,321	$5,396	$32,914
	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)		6,478	6,646	6,816	6,860	6,907	6,960	8,555	10,575	14,687	17,887	18,671	19,463	130,505
	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		6,478	6,646	6,816	6,860	6,907	6,960	8,555	10,575	14,687	17,887	18,671	19,463	130,505
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)		6,478	6,646	6,816	6,860	6,907	6,960	8,555	10,575	14,687	17,887	18,671	19,463	130,505
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$6,478	$6,646	$6,816	$6,860	$6,907	$6,960	$8,555	$10,575	$14,687	$17,887	$18,671	$19,463	$130,505

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.44
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8061% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7133% 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
Calculation of the Current Period Actual / Estimated Amount
January 2018 to December 2018

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		$0	$64	$788	$436	$934	$2,259	$18,519	$18,519	$18,519	$18,519	$18,519	$18,519	$115,595
	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 (excl from CWIP)		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	64	851	1,287	2,221	4,481	23,000	41,519	60,038	78,557	97,076	115,595	
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	64	851	1,287	2,221	4,481	23,000	41,519	60,038	78,557	97,076	115,595	
6.	Average Net Investment		0	32	457	1,069	1,754	3,351	13,740	32,259	50,778	69,297	87,816	106,335	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$0	$0	$2	$5	$8	$16	$66	$156	$246	$335	$425	$514	$1,773
	b. Debt Component Grossed Up For Taxes (C)		0	0	1	2	3	5	20	46	72	99	125	152	525
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	3	7	11	21	86	202	318	434	550	666	2,298
	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	3	7	11	21	86	202	318	434	550	666	2,298
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	3	7	11	21	86	202	318	434	550	666	2,298
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$3	$7	$11	$21	$86	$202	$318	$434	$550	$666	$2,298

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.44
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8061% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7133% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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ECRC 2018 ACTUAL/ESTIMATED TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2018 to December 2018

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend ELG Rule Compliance
(in Dollars)

Line	Description	Beginning of Period Amoun	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	$50,000	$50,000	$50,000	$150,000
	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 (excl from CWIP)		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	50,000	100,000	150,000	
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	0	0	0	50,000	100,000	150,000	
6.	Average Net Investment		0	0	0	0	0	0	0	0	0	25,000	75,000	125,000	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$121	$363	$605	$1,089
	b. Debt Component Grossed Up For Taxes (C)		0	0	0	0	0	0	0	0	0	36	107	178	321
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	157	470	783	1,410
	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	157	470	783	1,410
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	157	470	783	1,410
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$157	$470	$783	$1,410

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.45
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8061% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7133% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 2.5%
(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 2018 to December 2018

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 Amoun	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	$75,000	$400,000	$500,000	$500,000	$500,000	$500,000	$2,475,000
	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 (excl from CWIP)		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	75,000	475,000	975,000	1,475,000	1,975,000	2,475,000	
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	75,000	475,000	975,000	1,475,000	1,975,000	2,475,000	
6.	Average Net Investment		0	0	0	0	0	0	37,500	275,000	725,000	1,225,000	1,725,000	2,225,000	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$0	$0	$0	$0	$0	$0	$181	$1,331	$3,508	$5,927	$8,346	$10,765	$30,058
	b. Debt Component Grossed Up For Taxes (C)		0	0	0	0	0	0	54	393	1,035	1,749	2,463	3,177	8,871
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	235	1,724	4,543	7,676	10,809	13,942	38,929
	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	235	1,724	4,543	7,676	10,809	13,942	38,929
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	235	1,724	4,543	7,676	10,809	13,942	38,929
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$235	$1,724	$4,543	$7,676	$10,809	$13,942	$38,929

Notes:

(A) Applicable depreciable base for Big Bend; accounts 316.46 ($0) and 346.30 ($0)
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8061% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7133% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 2.9 and 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 2018 to June 2018

Form 42 - 9E
Page 1 of 2

Calculation of Revenue Requirement Rate of Return
(In Dollars)

	(1) Jurisdictional Rate Base **Actual May 2017** ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 1,611,554	33.14%	5.12%	1.6968%
Short Term Debt	118,708	2.44%	1.55%	0.0378%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	101,181	2.08%	2.55%	0.0531%
Common Equity	2,031,177	41.77%	10.25%	4.2815%
Accum. Deferred Inc. Taxes & Zero Cost ITC's	988,845	20.34%	0.00%	0.0000%
Deferred ITC - Weighted Cost	11,216	0.23%	7.78%	0.0179%
Total	$ 4,862,681	100.00%		6.09%

ITC split between Debt and Equity:

Long Term Debt	$ 1,611,554	Long Term Debt	42.84%
Short Term Debt	118,708	Short Term Debt	3.16%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	2,031,177	Equity - Common	54.00%
Total	$ 3,761,439	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = 0.0179% * 46.00%	0.0082%
Equity = 0.0179% * 54.00%	0.0097%
Weighted Cost	0.0179%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.2815%
Deferred ITC - Weighted Cost	0.0097%
	4.2912%
Times Tax Multiplier	1.34295
Total Equity Component	5.7628%

Total Debt Cost Rate:

Long Term Debt	1.6968%
Short Term Debt	0.0378%
Customer Deposits	0.0531%
Deferred ITC - Weighted Cost	0.0082%
Total Debt Component	1.7959%
	7.5587%

Notes:
Column (1) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012 and 2017 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 Settlement Agreement Dated September 27, 2017.
Column (4) - Column (2) x Column (3)

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
July 2018 to December 2018

Form 42 - 9E
Page 2 of 2

Calculation of Revenue Requirement Rate of Return
(In Dollars)

	(1) Jurisdictional Rate Base **Actual May 2018** ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 1,719,219	30.51%	5.13%	1.5652%
Short Term Debt	244,333	4.34%	2.18%	0.0945%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	96,005	1.70%	2.43%	0.0414%
Common Equity	2,367,502	42.02%	10.25%	4.3067%
Accum. Deferred Inc. Taxes & Zero Cost ITC's	1,187,473	21.07%	0.00%	0.0000%
Deferred ITC - Weighted Cost	20,116	0.36%	8.10%	0.0289%
Total	$ 5,634,648	100.00%		6.04%

ITC split between Debt and Equity:

Long Term Debt	$ 1,719,219	Long Term Debt	42.07%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	2,367,502	Equity - Common	57.93%
Total	$ 4,086,721	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = 0.0289% * 42.07%	0.0122%
Equity = 0.0289% * 57.93%	0.0167%
Weighted Cost	0.0289%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.3067%
Deferred ITC - Weighted Cost	0.0167%
	4.3234%
Times Tax Multiplier	1.34295
Total Equity Component	5.8061%

Total Debt Cost Rate:

Long Term Debt	1.5652%
Short Term Debt	0.0945%
Customer Deposits	0.0414%
Deferred ITC - Weighted Cost	0.0122%
Total Debt Component	1.7133%
	7.5194%

Notes:
Column (1) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012 and 2017 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 Settlement Agreement Dated September 27, 2017.
Column (4) - Column (2) x Column (3)

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TAMPA ELECTRIC COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE

ACTUAL/ESTIMATED TRUE-UP AMOUNT
FOR THE PERIOD
JANUARY 2018 THROUGH DECEMBER 2018
NOT INCLUDING THE COMPANY'S TWO
NEW PROPOSED ECRC PROJECTS

FORMS 42-1E THROUGH 42-7E

Tampa Electric Company

Form 42 - 1E

Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
Not Including the Company's Two New Proposed ECRC Projects
January 2018 to December 2018
(in Dollars)

Line		Period Amount
1.	Over/(Under) Recovery for the Current Period (Form 42-2E, Line 5)	$13,299,870
2.	Interest Provision (Form 42-2E, Line 6)	212,407
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 2019 to December 2019 (Lines 1 + 2 + 3)	$13,512,277

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
Not Including the Company's Two New Proposed ECRC Projects
January 2018 to December 2018

Form 42 - 2E

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)	$5,299,826	$4,794,184	$4,754,839	$4,804,461	$5,074,853	$5,873,006	$6,540,375	$6,493,000	$6,689,809	$5,928,024	$4,939,446	$4,863,661	$66,055,485
2.	True-Up Provision	508,445	508,445	508,445	508,445	508,445	508,445	508,445	508,445	508,445	508,445	508,445	508,449	6,101,344
3.	ECRC Revenues Applicable to Period (Lines 1 + 2) [1]	5,808,271	5,302,629	5,263,284	5,312,906	5,583,298	6,381,451	7,048,820	7,001,445	7,198,254	6,436,469	5,447,891	5,372,110	72,156,829
4.	Jurisdictional ECRC Costs													
	a. O & M Activities (Form 42-5E, Line 9)	1,874,870	2,166,060	1,373,137	959,540	1,185,543	743,043	405,177	403,175	395,441	910,226	1,021,725	1,269,328	12,707,265
	b. Capital Investment Projects (Form 42-7E, Line 9)	3,891,399	3,881,399	3,871,500	3,861,963	3,853,761	3,845,686	3,837,441	3,831,106	3,828,163	3,824,424	3,815,756	3,807,095	46,149,693
	c. Total Jurisdictional ECRC Costs	5,766,269	6,047,459	5,244,637	4,821,503	5,039,304	4,588,729	4,242,618	4,234,281	4,223,604	4,734,650	4,837,481	5,076,423	58,856,958
5.	Over/Under Recovery (Line 3 - Line 4c) [1]	42,002.00	(744,830)	18,647	491,403	543,994.00	1,792,722.00	2,806,202.00	2,767,164.00	2,974,650.00	1,701,819.00	610,410.00	295,687	13,299,870
6.	Interest Provision (Form 42-3E, Line 10)	9,356	8,341	8,197	8,382	8,410	9,750	14,605	20,782	25,644	31,016	33,986	33,938	212,407
7.	Beginning Balance True-Up & Interest Provision [1]	6,101,344	5,644,257	4,399,323	3,917,722	3,909,062	3,953,021	5,247,048	7,559,410	9,838,911	12,330,760	13,555,150	13,691,101	6,101,344
	a. Deferred True-Up from January to December 2018 (Order No. PSC-2018-0014-FOF-EI)	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666
8.	True-Up Collected/(Refunded) (see Line 2)	(508,445)	(508,445)	(508,445)	(508,445)	(508,445)	(508,445)	(508,445)	(508,445)	(508,445)	(508,445)	(508,445)	(508,449)	(6,101,344)
9.	End of Period Total True-Up (Lines 5+6+7+7a+8) [1]	7,142,923	5,897,989	5,416,388	5,407,728	5,451,687	6,745,714	9,058,076	11,337,577	13,829,426	15,053,816	15,189,767	15,010,943	15,010,943
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]	$7,142,923	$5,897,989	$5,416,388	$5,407,728	$5,451,687	$6,745,714	$9,058,076	$11,337,577	$13,829,426	$15,053,816	$15,189,767	$15,010,943	$15,010,943

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ECRC 2018 ACTUAL/ESTIMATED TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
Not Including the Company's Two New Proposed ECRC Projects
January 2018 to December 2018

Form 42 - 3E

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 42-2E, Line 7 + 7a + 10)	$7,600,010	$7,142,923	$5,897,989	$5,416,388	$5,407,728	$5,451,687	$6,745,714	$9,058,076	$11,337,577	$13,829,426	$15,053,816	$15,189,767	
2.	Ending True-Up Amount Before Interest	7,133,567	5,889,648	5,408,191	5,399,346	5,443,277	6,735,964	9,043,471	11,316,795	13,803,782	15,022,800	15,155,781	14,977,005	
3.	Total of Beginning & Ending True-Up (Lines 1 + 2) [1]	14,733,577	13,032,571	11,306,180	10,815,734	10,851,005	12,187,651	15,789,185	20,374,871	25,141,359	28,852,226	30,209,597	30,166,772	
4.	Average True-Up Amount (Line 3 x 1/2) [1]	7,366,789	6,516,286	5,653,090	5,407,867	5,425,503	6,093,826	7,894,593	10,187,436	12,570,680	14,426,113	15,104,799	15,083,386	
5.	Interest Rate (First Day of Reporting Business Month)	1.58%	1.46%	1.62%	1.86%	1.85%	1.86%	1.98%	2.45%	2.45%	2.45%	2.70%	2.70%	
6.	Interest Rate (First Day of Subsequent Business Month)	1.46%	1.62%	1.86%	1.85%	1.86%	1.98%	2.45%	2.45%	2.45%	2.70%	2.70%	2.70%	
7.	Total of Beginning & Ending Interest Rates (Lines 5 + 6) [1]	3.04%	3.08%	3.48%	3.71%	3.71%	3.84%	4.43%	4.90%	4.90%	5.15%	5.40%	5.40%	
8.	Average Interest Rate (Line 7 x 1/2) [1]	1.520%	1.540%	1.740%	1.855%	1.855%	1.920%	2.215%	2.450%	2.450%	2.575%	2.700%	2.700%	
9.	Monthly Average Interest Rate (Line 8 x 1/12) [1]	0.127%	0.128%	0.145%	0.155%	0.155%	0.160%	0.185%	0.204%	0.204%	0.215%	0.225%	0.225%	$212,407

DOCKET NO. 20180007-EI
ECRC 2018 ACTUAL/ESTIMATED TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
Not Including the Company's Two New Proposed ECRC Projects
January 2018 to December 2018

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 FGD Integration	$1,894,681	$4,423,789	($2,529,108)	-57.2%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0.0%
	c. SO_2 Emissions Allowances	(98)	9,151	(9,249)	-101.1%
	d. Big Bend Units 1 & 2 FGD	570,804	2,200,000	(1,629,196)	-74.1%
	e. Big Bend PM Minimization and Monitoring	406,562	611,283	(204,721)	-33.5%
	f. Big Bend NO_x Emissions Reduction	78,693	138,956	(60,263)	-43.4%
	g. NPDES Annual Surveillance Fees	35,883	34,500	1,383	4.0%
	h. Gannon Thermal Discharge Study	0	0	0	0.0%
	i. Polk NO_x Emissions Reduction	5,317	19,988	(14,671)	-73.4%
	j. Bayside SCR Consumables	111,102	203,882	(92,779)	-45.5%
	k. Big Bend Unit 4 SOFA	0	37,200	(37,200)	-100.0%
	l. Big Bend Unit 1 Pre-SCR	39	37,200	(37,161)	-99.9%
	m. Big Bend Unit 2 Pre-SCR	1,450	37,200	(35,750)	-96.1%
	n. Big Bend Unit 3 Pre-SCR	3,808	37,200	(33,392)	-89.8%
	o. Clean Water Act Section 316(b) Phase II Study	74,158	321,000	(246,842)	-76.9%
	p. Arsenic Groundwater Standard Program	0	0	0	0.0%
	q. Big Bend 1 SCR	351,102	1,498,585	(1,147,483)	-76.6%
	r. Big Bend 2 SCR	361,113	1,629,977	(1,268,864)	-77.8%
	s. Big Bend 3 SCR	1,553,384	1,694,774	(141,390)	-8.3%
	t. Big Bend 4 SCR	651,145	1,061,162	(410,017)	-38.6%
	u. Mercury Air Toxics Standards	24,378	231,000	(206,622)	-89.4%
	v. Greenhouse Gas Reduction Program	95,974	93,149	2,825	3.0%
	w. Big Bend Gypsum Storage Facility	1,638,273	1,663,000	(24,727)	-1.5%
	x. CCR Rule - Phase I	38,250	0	38,250	N/A
	y. Big Bend ELG Rule Study	54,007	0	54,007	N/A
	z. CCR Rule - Phase II	4,757,238	6,125,000	(1,367,762)	-22.3%
2.	Total Investment Projects - Recoverable Costs	$12,707,265	$22,107,996	($9,400,732)	-42.5%
3.	Recoverable Costs Allocated to Energy	$12,597,223	$21,752,496	($9,155,273)	-42.1%
4.	Recoverable Costs Allocated to Demand	$110,042	$355,500	($245,459)	-69.0%

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-2018-0014-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
Not Including the Company's Two New Proposed ECRC Projects
January 2018 to December 2018

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 FGD Integration	452,214	273,733	291,066	358,824	331,130	187,714	0	0	0	0	0	0	1,894,681		$1,894,681
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	(34)	5	8	(16)	22	(83)	0	0	0	0	0	0	(98)		(98)
d.	Big Bend Units 1 & 2 FGD	17,413	66,376	55,024	54,100	100,066	19,825	43,000	43,000	43,000	43,000	43,000	43,000	570,804		570,804
e.	Big Bend PM Minimization and Monitoring	52,762	44,712	67,899	54,273	45,912	27,938	15,000	15,000	8,065	25,000	25,000	25,000	406,562		406,562
f.	Big Bend NO_x Emissions Reduction	37	34,122	266	2,757	78	29,434	2,000	2,000	2,000	2,000	2,000	2,000	78,693		78,693
g.	NPDES Annual Surveillance Fees	34,500	0	0	0	0	1,383	0	0	0	0	0	0	35,883	$35,883	
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	688	853	440	0	0	35	950	950	400	0	250	750	5,317		5,317
j.	Bayside SCR and Ammonia	16,454	3,210	8,560	12,325	3,210	11,843	12,500	10,000	9,000	8,000	8,000	8,000	111,102		111,102
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	39	0	0	0	0	0	0	0	0	0	39		39
m.	Big Bend Unit 2 Pre-SCR	635	0	0	815	0	0	0	0	0	0	0	0	1,450		1,450
n.	Big Bend Unit 3 Pre-SCR	0	0	0	0	3,714	94	0	0	0	0	0	0	3,808		3,808
o.	Clean Water Act Section 316(b) Phase II Study	4,499	14,303	174	21,348	75	9	0	1,250	1,250	1,250	12,500	17,500	74,158	74,158	
p.	Arsenic Groundwater Standard Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
q.	Big Bend 1 SCR	6,777	18,340	3,087	32,717	33,063	14,694	40,801	41,277	39,690	50,168	24,607	45,881	351,102		351,102
r.	Big Bend 2 SCR	4,267	6,863	6,549	54,763	9,514	7,682	45,405	45,722	47,627	60,328	24,607	47,786	361,113		361,113
s.	Big Bend 3 SCR	125,936	154,048	270,635	166,420	280,869	192,408	60,405	60,722	62,627	33,098	83,425	62,791	1,553,384		1,553,384
t.	Big Bend 4 SCR	58,197	89,093	46,317	54,593	33,834	55,218	51,866	50,754	48,532	54,882	65,836	42,023	651,145		651,145
u.	Mercury Air Toxics Standards	0	0	7,823	55	0	0	3,250	2,500	3,250	2,500	2,500	2,500	24,378		24,378
v.	Greenhouse Gas Reduction Program	2,825	0	0	0	93,149	0	0	0	0	0	0	0	95,974		95,974
w.	Big Bend Gypsum Storage Facility (East 40)	163,867	110,837	59,289	124,795	239,532	159,952	130,000	130,000	130,000	130,000	130,000	130,000	1,638,273		1,638,273
x.	CCR Rule - Phase I	(3,500)	14,103	14,033	1,844	9,875	1,895	0	0	0	0	0	0	38,250		38,250
y.	BB ELG Rule Study	0	11,472	0	9,832	0	32,703	0	0	0	0	0	0	54,007		54,007
z.	CCR Rule - Phase II	937,333	1,323,990	541,927	10,095	1,500	297	0	0	0	500,000	600,000	842,097	4,757,238		4,757,238
2.	Total of O&M Activities	1,874,870	2,166,060	1,373,137	959,540	1,185,543	743,043	405,177	403,175	395,441	910,226	1,021,725	1,269,328	12,707,265	$110,042	$12,597,223
3.	Recoverable Costs Allocated to Energy	1,835,871	2,151,757	1,372,963	938,192	1,185,468	741,650	405,177	401,925	394,191	908,976	1,009,225	1,251,828	12,597,223		
4.	Recoverable Costs Allocated to Demand	38,999	14,303	174	21,348	75	1,393	0	1,250	1,250	1,250	12,500	17,500	110,042		
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)	1,835,871	2,151,757	1,372,963	938,192	1,185,468	741,650	405,177	401,925	394,191	908,976	1,009,225	1,251,828	12,597,223		
8.	Jurisdictional Demand Recoverable Costs (B)	38,999	14,303	174	21,348	75	1,393	0	1,250	1,250	1,250	12,500	17,500	110,042		
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$1,874,870	$2,166,060	$1,373,137	$959,540	$1,185,543	$743,043	$405,177	$403,175	395,441	910,226	$1,021,725	$1,269,328	$12,707,265		

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Form 42 - 6E

Tampa Electric Company

Environmental Cost Recovery Clause

Calculation of the Current Period Actual / Estimated Amount

Not including the Company's Two New Proposed ECRC Projects

January 2018 to December 2018

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 FGD Integration	$960,478	$1,063,216	($102,738)	-9.7%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	249,611	280,951	(31,340)	-11.2%
	c. Big Bend Unit 4 Continuous Emissions Monitors	51,106	55,016	(3,910)	-7.1%
	d. Big Bend Fuel Oil Tank No. 1 Upgrade	55,003	35,856	19,147	53.4%
	e. Big Bend Fuel Oil Tank No. 2 Upgrade	90,462	58,969	31,493	53.4%
	f. Big Bend Unit 1 Classifier Replacement	80,406	85,047	(4,641)	-5.5%
	g. Big Bend Unit 2 Classifier Replacement	58,125	61,751	(3,626)	-5.9%
	h. Big Bend Section 114 Mercury Testing Platform	8,561	9,406	(845)	-9.0%
	i. Big Bend Units 1 & 2 FGD	6,053,972	6,674,906	(620,934)	-9.3%
	j. Big Bend FGD Optimization and Utilization	1,554,594	1,712,875	(158,281)	-9.2%
	k. Big Bend NO_x Emissions Reduction	499,295	562,354	(63,059)	-11.2%
	l. Big Bend PM Minimization and Monitoring	1,809,236	1,989,614	(180,378)	-9.1%
	m. Polk NO_x Emissions Reduction	113,291	123,356	(10,065)	-8.2%
	n. Big Bend Unit 4 SOFA	198,216	218,523	(20,307)	-9.3%
	o. Big Bend Unit 1 Pre-SCR	137,627	149,608	(11,981)	-8.0%
	p. Big Bend Unit 2 Pre-SCR	130,774	142,854	(12,080)	-8.5%
	q. Big Bend Unit 3 Pre-SCR	233,148	256,173	(23,025)	-9.0%
	r. Big Bend Unit 1 SCR	7,960,486	8,698,396	(737,910)	-8.5%
	s. Big Bend Unit 2 SCR	8,407,134	9,195,158	(788,024)	-8.6%
	t. Big Bend Unit 3 SCR	6,968,976	7,628,421	(659,445)	-8.6%
	u. Big Bend Unit 4 SCR	5,420,471	5,919,666	(499,195)	-8.4%
	v. Big Bend FGD System Reliability	2,080,439	2,325,371	(244,932)	-10.5%
	w. Mercury Air Toxics Standards	824,512	928,320	(103,808)	-11.2%
	x. SO_2 Emissions Allowances	(2,601)	(3,015)	414	-13.7%
	y. Big Bend Gypsum Storage Facility	2,073,568	2,316,204	(242,636)	-10.5%
	z. CCR Rule - Phase I	130,505	224,233	(93,728)	-41.8%
	aa. CCR Rule - Phase II	2,298	0	2,298	N/A
2.	Total Investment Projects - Recoverable Costs	$46,149,693	$50,713,229	($4,563,536)	-9.0%
3.	Recoverable Costs Allocated to Energy	$45,871,425	$50,394,171	($4,522,746)	-9.0%
4.	Recoverable Costs Allocated to Demand	$278,268	$319,058	($40,790)	-12.8%

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-2018-0014-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
Not Including the Company's Two New Proposed ECRC Projects
January 2018 to December 2018

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 FGD Integration	1	$81,171	$80,989	$80,808	$80,626	$80,445	$80,262	$79,814	$79,634	$79,453	$79,273	$79,092	$78,911	$960,478		$960,478
	b.	Big Bend Units 1 and 2 Flue Gas Conditioning	2	21,372	21,270	21,168	21,066	20,965	20,863	20,737	20,636	20,535	20,434	20,333	20,232	249,611		249,611
	c.	Big Bend Unit 4 Continuous Emissions Monitors	3	4,344	4,330	4,314	4,300	4,285	4,271	4,246	4,232	4,218	4,203	4,189	4,174	51,106		51,106
	d.	Big Bend Fuel Oil Tank No. 1 Upgrade	4	2,815	2,806	2,796	2,787	2,778	2,770	6,456	6,423	6,391	6,359	6,327	6,295	55,003	$55,003	
	e.	Big Bend Fuel Oil Tank No. 2 Upgrade	5	4,629	4,614	4,600	4,584	4,570	4,555	10,617	10,564	10,511	10,459	10,406	10,353	90,462	90,462	
	f.	Big Bend Unit 1 Classifier Replacement	6	6,859	6,830	6,803	6,775	6,748	6,720	6,680	6,653	6,626	6,599	6,570	6,543	80,406		80,406
	g.	Big Bend Unit 2 Classifier Replacement	7	4,954	4,934	4,915	4,896	4,877	4,858	4,830	4,810	4,791	4,773	4,753	4,734	58,125		58,125
	h.	Big Bend Section 114 Mercury Testing Platform	8	725	722	721	719	717	716	712	709	708	706	704	702	8,561		8,561
	i.	Big Bend Units 1 & 2 FGD	9	514,191	512,541	510,891	509,241	507,592	505,942	503,032	501,391	499,750	498,108	496,467	494,826	6,053,972		6,053,972
	j.	Big Bend FGD Optimization and Utilization	10	126,787	126,722	126,673	127,106	128,669	130,581	130,379	130,544	130,973	131,514	132,054	132,592	1,554,594		1,554,594
	k.	Big Bend NO_x Emissions Reduction	11	42,042	41,978	41,914	41,850	41,785	41,721	41,494	41,430	41,366	41,302	41,239	41,174	499,295		499,295
	l.	Big Bend PM Minimization and Monitoring	12	153,110	152,726	152,343	151,960	151,576	151,193	150,342	149,960	149,579	149,197	148,816	148,434	1,809,236		1,809,236
	m.	Polk NO_x Emissions Reduction	13	9,607	9,579	9,551	9,524	9,496	9,467	9,414	9,386	9,358	9,331	9,303	9,275	113,291		113,291
	n.	Big Bend Unit 4 SOFA	14	16,766	16,725	16,685	16,645	16,604	16,565	16,471	16,431	16,391	16,351	16,311	16,271	198,216		198,216
	o.	Big Bend Unit 1 Pre-SCR	15	11,675	11,640	11,605	11,571	11,536	11,502	11,436	11,401	11,366	11,333	11,298	11,264	137,627		137,627
	p.	Big Bend Unit 2 Pre-SCR	16	11,082	11,051	11,021	10,990	10,959	10,929	10,867	10,836	10,806	10,775	10,744	10,714	130,774		130,774
	q.	Big Bend Unit 3 Pre-SCR	17	19,734	19,684	19,634	19,583	19,533	19,484	19,374	19,324	19,275	19,224	19,175	19,124	233,148		233,148
	r.	Big Bend Unit 1 SCR	18	674,992	673,045	671,098	669,150	667,203	665,256	661,467	659,530	657,592	655,655	653,717	651,781	7,960,486		7,960,486
	s.	Big Bend Unit 2 SCR	19	712,268	710,328	708,390	706,451	704,511	702,572	698,591	696,663	694,733	692,805	690,875	688,947	8,407,134		8,407,134
	t.	Big Bend Unit 3 SCR	20	590,325	588,737	587,150	585,562	583,973	582,386	579,090	577,510	575,930	574,351	572,771	571,191	6,968,976		6,968,976
	u.	Big Bend Unit 4 SCR	21	456,706	455,523	454,342	453,169	452,014	450,873	449,762	449,995	450,229	450,462	449,286	448,110	5,420,471		5,420,471
	v.	Big Bend FGD System Reliability	22	175,463	175,139	174,817	174,494	174,170	173,847	172,889	172,567	172,245	171,924	171,603	171,281	2,080,439		2,080,439
	w.	Mercury Air Toxics Standards	23	68,615	68,478	68,407	68,337	68,454	68,315	67,999	67,924	68,881	69,839	69,701	69,562	824,512		824,512
	x.	SO_2 Emissions Allowances (B)	24	(218)	(218)	(218)	(217)	(217)	(217)	(216)	(216)	(216)	(216)	(216)	(216)	(2,601)		(2,601)
	y.	Big Bend Gypsum Storage Facility	25	174,907	174,580	174,253	173,927	173,600	173,274	172,317	171,992	171,667	171,342	171,017	170,692	2,073,568		2,073,568
	z.	CCR Rule - Phase I	26	6,478	6,646	6,816	6,860	6,907	6,960	8,555	10,575	14,687	17,887	18,671	19,463	130,505	130,505	
	aa.	CCR Rule - Phase II	27	0	0	3	7	11	21	86	202	318	434	550	666	2,298	2,298	
2.		Total Investment Projects - Recoverable Costs		3,891,399	3,881,399	3,871,500	3,861,963	3,853,761	3,845,686	3,837,441	3,831,106	3,828,163	3,824,424	3,815,756	3,807,095	46,149,693	$278,268	$45,871,425
3.		Recoverable Costs Allocated to Energy		3,877,477	3,867,333	3,857,285	3,847,725	3,839,495	3,831,380	3,811,727	3,803,342	3,796,256	3,789,285	3,779,802	3,770,318	45,871,425		
4.		Recoverable Costs Allocated to Demand		13,922	14,066	14,215	14,238	14,266	14,306	25,714	27,764	31,907	35,139	35,954	36,777	278,268		
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)		3,877,477	3,867,333	3,857,285	3,847,725	3,839,495	3,831,380	3,811,727	3,803,342	3,796,256	3,789,285	3,779,802	3,770,318	45,871,425		
8.		Jurisdictional Demand Recoverable Costs (D)		13,922	14,066	14,215	14,238	14,266	14,306	25,714	27,764	31,907	35,139	35,954	36,777	278,268		
9.		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)		$3,891,399	$3,881,399	$3,871,500	$3,861,963	$3,853,761	$3,845,686	$3,837,441	$3,831,106	$3,828,163	$3,824,424	$3,815,756	$3,807,095	$46,149,693		

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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DOCKET NO. 20180007-EI
ECRC 2018 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT NO. PAR-3, DOCUMENT NO. 7, PAGE 1 OF 1

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20180007-EI

IN RE: TAMPA ELECTRIC'S ENVIRONMENTAL

COST RECOVERY

ACTUAL/ESTIMATED TRUE-UP

JANUARY 2018 THROUGH DECEMBER 2018

TESTIMONY

OF

PAUL L. CARPINONE

FILED: JULY 25, 2018

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PAUL L. CARPINONE

Q. Please state your name, address, occupation and employer.

A. My name is Paul L. Carpinone. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Environmental Services in the Environmental Services Department.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science degree in Water Resources Engineering Technology from the Pennsylvania State University in 1978. I have been a Registered Professional Engineer in the states of Florida and Pennsylvania since 1984. Prior to joining Tampa Electric, I worked for Seminole Electric Cooperative as a Civil Engineer in various positions and in environmental consulting. In February 1988, I joined Tampa Electric as a Principal Engineer, and I have primarily worked in the area of

Environmental. In 2006, I became Director of Environmental Services. My responsibilities include the development and administration of the company's environmental policies and goals. I am also responsible for ensuring resources, procedures and programs meet or surpass compliance with applicable environmental requirements, and that rules and polices are in place and functioning appropriately and consistently throughout the company.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide record support for the Commission's approval of two environmental programs for cost recovery through the Environmental Cost Recovery Clause ("ECRC"). Those projects include the company's Big Bend Unit 1 Section 316(b) Impingement Mortality Project ("Impingement Mortality Project") and the company's Big Bend Station Effluent Limitations Guidelines Rule Compliance Program ("Big Bend ELG Rule Compliance Program").

Impingement Mortality Project

Q. Please describe the environmental requirements necessitating the Impingement Mortality Project?

A. 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.

The rule addresses impacts to aquatic life resulting from operation of cooling water systems in the U.S. from either impingement or entrainment. Impingement mortality occurs when fish and shellfish are pinned against the intake system screens and unable to get free. Entrainment mortality occurs when small fish, eggs, and larvae pass through the protective screens and into the cooling system. The rule allows for seven different approaches to impingement mortality reduction at affected facilities, each of which, if it meets the goals defined for the approach by the rule, would be considered fully compliant. These approaches are

a. closed-cycle cooling tower;
b. 0.5 feet per second ("fps") through-screen design velocity;
c. 0.5 fps through-screen actual velocity;
d. existing offshore velocity cap;

e. modified traveling screens;

f. system of technologies as the BTA for impingement mortality; and,

g. meet impingement mortality performance standard.

For entrainment compliance, the rule requires the evaluation of closed-cycle cooling, alternative water supplies, and fine mesh screens in terms of feasibility, cost, and effectiveness for a site-specific determination by the Florida Department of Environmental Protection ("FDEP") Director. With respect to Big Bend Station, the FDEP Director will make this determination by reviewing the following study elements which are required to be submitted with the National Pollutant Discharge Elimination System ("NPDES") permit renewal application. These elements are:

a. 40 CFR 122.21(r)(2), Source Water Physical Data;

b. 40 CFR 122.21(r)(3), Cooling Water Intake Structure Data;

c. 40 CFR 122.21(r)(4), Baseline Biological Characterization;

d. 40 CFR 122.21(r)(5), Cooling Water System Data;

e. 40 CFR 122.21(r)(6), Chosen Method of Compliance with Impingement Mortality Standard;

f. 40 CFR 122.21(r)(7) Entrainment Performance Studies; and,

g. 40 CFR 122.21(r)(8) Operational Status.

h. 40 CFR 122.21(r)(9), Entrainment Characterization Study;

i. 40 CFR 122.21(r)(10), Feasibility and Cost Study;

j. 40 CFR 122.21(r)(11), Benefits Valuation Study;

k. 40 CFR 122.21(r)(12) Environmental and Other Impacts; and,

l. 40 CFR 122.21(r)(13) Peer Review of (r)(10), (r)(11), and (r)(12).

Tampa Electric continues to perform the required studies under its previously approved Clean Water Act Section 316(b) Phase II Study ECRC project.

As stated above, compliance with Section 316(b) is tied to the renewal of the NPDES permit for the facility; however, the rule included a provision to allow a request for an alternative schedule for those facilities that had permit renewal dates within 45 months of the finalization of the rule. Big Bend Station requested such an alternative schedule to allow time to complete the study elements. Within six months of the finalization of the company’s Big Bend Station NPDES permit, which is currently undergoing renewal by the FDEP, Tampa Electric will submit a plan of study which will be used by FDEP to establish the compliance schedule. However, the modernization of Big Bend Unit 1 to a highly efficient, natural gas-fired unit (the "Big Bend Unit 1 Modernization") requires NPDES permit modifications, and FDEP has agreed that it is appropriate to address impingement mortality in conjunction with the Big Bend Unit 1 Modernization. In addition, complying with the rule requirements now will benefit customers because integrating the impingement mortality equipment into the Big Bend Unit 1 Modernization project planning, design, and construction work will be more efficient than retrofitting the unit with the impingement mortality compliance equipment at a later date due to the additional outage time that would be needed to perform the modifications later.

Q. What is the specific scope of the company's petition for approval of the Impingement Mortality Project?

A. The petition applies to impingement mortality requirements of Section 316(b) for the CWIS currently shared by Big Bend Units 1 and 2. If the company's Clean Water Act Section 316(b) Phase II Study results indicate that additional changes are needed to meet entrainment mortality requirements, this new system will accommodate installation of fine mesh screens, and cost recovery for such work would be addressed in a separate request. In addition, impingement and entrainment mortality compliance for Big Bend Units 3 and 4 will need to be addressed at a later date based on the results of the studies the company is performing under its Clean Water Act Section 316(b) Phase II Study ECRC project and the NPDES permit renewal.

Q What actions must the company take in order to comply with Rule 316(b) and the company NPDES permit?

A. In order to comply with Rule 316(b) and its NPDES permit, Tampa Electric must make modifications to its existing CWIS shared by Big Bend Units 1 and 2 for purposes of withdrawing once-through cooling water from Tampa Bay. Each unit is currently equipped with two 50 percent cooling water pumps which have dedicated traveling screens to protect the pumps against entrainment of debris. This intake structure will be modified to operate with the modernized Big Bend Unit 1, and new dual flow modified traveling screens as well as a fish collection and return system will be installed to comply with the impingement mortality requirements of Section 316(b). The new system will allow aquatic life impinged on the screens to be safely returned to a suitable location.

The company hired an engineering firm to conduct studies to evaluate Section 316(b) impingement mortality compliance and has identified the modified traveling screens with fish return as the most cost-effective solution to continue operating Big Bend Unit 1 in compliance with Section 316(b). The selected solution complies with option (e) in the list of compliance options stated above.

Engineering work for the Big Bend Unit 1 Section 316(b) Impingement Mortality project began mid-year in 2018 to support equipment procurement and a construction start date in 2021 when Big Bend Units 1 and 2 will be shut down for the modernization project work. The Impingement Mortality Project will be completed prior to commercial operation of the Big Bend Unit 1 Modernization in January 2023.

Q. Please describe the costs of the Impingement Mortality Project.

The total estimated cost of the project is $15.6 million. The following table reflects a breakdown of the project components and their projected costs.

Big Bend Unit 1 Section 316(b) Impingement Mortality Project

	2018 ($000)	2019 ($000)	2020 ($000)	2021 ($000)	2022 ($000)	2023 ($000)	Total ($000)
Capital							
Engineering	1,650	-	-	-	-	-	1,650
Equipment	325	3,000	500	-	-	-	3,825
Construction	-	-	-	500	7,750	250	8,500
Owners Costs	500		500	500	-	-	1,500
Demolition / Retirement	-	-	-	-	170	-	170
Total	2,475	3,000	1,000	1,000	7,920	250	15,645
In-Service Annual O&M[1]							
Variable O&M	-	-	-	-	-	67	
Operating Labor	-	-	-	-	-	25	
Maintenance Material	-	-	-	-	-	99	
Maintenance Labor	-	-	-	-	-	65	
Total	-	-	-	-	-	256	

1 Estimated annual O&M expense after commercial in-service date, in 2023 dollars.

Q. What steps will the company take to ensure that the costs of the project are reasonable?

A. Tampa Electric will follow its usual prudent and practical procurement policies, including competitive bidding for project components, to ensure it purchases equipment and services at the best prices available. These estimated annual costs may vary due to timing of the work and will continue to be refined as design and engineering work progresses. Tampa Electric will provide updated cost estimates in its annual ECRC filings.

Q. Is the proposed project essential to enable the company to comply with applicable environmental mandates?

A. Yes. Tampa Electric cannot continue operating Big Bend Unit 1 in compliance with Section 316(b) without making the CWIS modifications I have described. Section 316(b) compliance requires these modifications regardless of whether Big Bend Unit 1 is modernized to a natural gas-fired unit or continues to operate as coal-fired.

Q. What is the Commission's policy governing ECRC cost recovery?

A. The Commission's policy for initial cost recovery approval of an ECRC eligible project is set forth in Order No. PSC-94-0044-FOF-EI issued January 12, 1994 in Docket No. 930613-EI, In re: Gulf Power Company, ("the Gulf Order") as follows:

> Upon petition, we shall allow the recovery of costs associated with an environmental compliance activity through the environmental cost recovery factor if:
>
> 1. such costs were prudently incurred after April 13, 1993:
> 2. the activity is legally required to comply with a governmentally imposed

environmental regulation enacted, became effective, or whose effect was triggered after the company's last test year upon which rates are based; and,

3. such costs are not recovered through some other cost recovery mechanism or through base rates.

Q. Does the Impingement Mortality Project qualify for ECRC cost recovery under these principles?

A. Yes. The proposed CWIS modifications merit ECRC cost recovery under the criteria set forth by the Commission in the Gulf Order. All costs associated with the project will be prudently incurred after April 13, 1993. The CWIS modifications to Big Bend Unit 1 are required in order for Tampa Electric to continue complying with the requirements of Section 316(b) and its NPDES permit. The need to construct CWIS modifications has been triggered after the company’s last test year upon which rates are currently based. Finally, the costs of the proposed CWIS modifications are not recovered through some other cost recovery mechanism or through base rates. Like the Gulf Power ECRC project approved in Docket No. 980007-EI, the proposed CWIS modifications are needed in order to enable

Tampa Electric to continue complying with applicable environmental mandates.

Q. What is the schedule for the project?

A. Tampa Electric expects to begin incurring 316(b) impingement mortality compliance costs associated with the proposed CWIS modifications for Big Bend Unit 1 in 2018. Project costs will be subject to audit by the Commission.

Q. How should the projects costs be allocated?

A. The project capital expenditures should be allocated to rate classes on a demand basis, and operation and maintenance expenses should be allocated to rate classes on an energy basis.

Big Bend ELG Rule Compliance Program

Q. Please describe the Big Bend ELG Rule Compliance Program?

A. The Big Bend ELG Rule Compliance Program is designed to enable Tampa Electric to comply with the Environmental Protection Agency's legally required ELG rule.

On November 3, 2015 the Environmental Protection Agency

("EPA") published the final Steam Electric Power Generating Effluent Limitations Guidelines ("ELG") in the Federal Register. The effective date of the rule is January 4, 2016. The ELG 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, 2018, and no later than December 31, 2023. Since these limitations will be incorporated in the National Pollutant Discharge Elimination System ("NPDES") permits, the exact compliance date will be determined through discussions with the Florida Department of Environmental Protection ("FDEP"), whom EPA has delegated to administer these permits. EPA extended the near-term deadlines for FGD waste water and bottom ash transport water to as soon as possible after November 1, 2020, while those limits are under consideration.

Q. What Tampa Electric facilities are affected by the ELG Rule?

Tampa Electric facilities located at the company's Big Bend Station are affected by the ELG Rule. Big Bend Station operates four coal-fired steam electric power generating units equipped with electrostatic precipitators, Selective Catalytic Reduction ("SCR") and wet Limestone Forced Oxidized ("LSFO") Flue Gas Desulfurization ("FGD") systems. The FGD system is designed to operate at a chloride concentration of no more than 30,000 ppm chlorides. Chloride control is obtained by blowing down the FGD system at approximately 230 gpm. This blow-down stream is sent to a physical chemical treatment system to remove solids, some metals, ammonia and adjust pH prior to discharge to Tampa Bay via the once-through condenser cooling system water. This treatment system will need to be modified or replaced in order to achieve compliance with the new EPA regulations.

Other ELG waste stream categories present at Big Bend Station are bottom and fly ash transport water, which will be used for FGD scrubber make-up water, as allowed by the ELG Rule. There are no other facilities at Big Bend Station affected by the ELG Rule.

Q. Please describe the Big Bend ELG Study Program.

A. On February 2, 2016 Tampa Electric Company submitted its Petition for Approval of its Big Bend ELG Study Program for cost recovery through the Environmental Cost Recovery Clause. The Big Bend ELG Study Program was needed to determine the most appropriate ELG compliance measure for that station. The Big Bend ELG Study Program was approved in Order No. PSC-16-0248-PAA-EI issued June 28, 2016 in Docket No. 20160027-EI, and confirmed in Consummating Order No. PSC-16-0290-CO-EI issued July 25, 2016 in Docket No. 20160027-EI.

The Study identified the technically and commercially available technologies which could be viable candidates to treat the Tampa Electric Big Bend Station combined effluent streams in order to bring the streams into compliance with the more stringent requirements under the ELG Rule. The company has reviewed several options and selected the deep well injection solution based on total project costs, including annual operating costs. This option allows the company to use one option to comply with ELG Rule parameters. Although capital costs for the options considered varied, the deep well injection solution is one of the least costly when capital costs and annual operating costs are considered. Combined with the fact that the deep well injection solution does not degrade unit performance as other options do, it is the best choice for Tampa Electric's Big Bend Station ELG Rule compliance.

With the Study now completed, the company must obtain environmental permitting and engage in the construction of a test injection well to ensure that the selected deep well injection method satisfies FDEP requirements. Once the test results are confirmed, the test injection well will be converted to a permanent deep injection well system of two wells to comply with the ELG Rule. Obtaining Commission approval for recovery of permitting, engineering, and construction costs for both the test well and the permanent deep injection well systems is the purpose of this section of my testimony.

Q. What are the estimated costs of the Big Bend Station ELG Rule Compliance Program for which Tampa Electric is requesting ECRC recovery?

A. Tampa Electric requests recovery of capital costs, estimated to be in a range of from $18 million to $26 million, for preconstruction design, engineering, permitting, and installation of two injection wells, together with one of three options the company is considering for pretreatment of the effluent discharge. The pretreatment requirement will be determined after the FDEP review of the test well results. The capital costs could range from an estimated $18 million if no water softening is required and the company’s permit allows blending wastewater with county-treated effluent, to approximately $21 million if 30 percent softening is required, and up to approximately $26 million if full softening treatment is required. For purposes of illustration, the following table describes the component capital costs for the option of deep well injection with the pretreatment of 30 percent softening of the water prior to injection.

Capital Costs by Year

Deep Injection Wells with Pre-Treatment of 30% Water Softening

	2018 ($000)	**2019 ($000)**	**2020 ($000)**	**2021 ($000)**	**Total ($000)**
Capital					
Permitting and Pre-Construction Engineering Design	150	250	700	-	1,100
Construction Engineering	-		1,800	400	2,200
Well Construction (2 wells)	-		5,000	3,000	8,000
Water Treatment (Softening)	-		7,100	2,600	9,700
Total	150	250	14,600	6,000	21,000

The permit application for deep well injection will be submitted to the FDEP and will address testing, hydro-geological impacts, and construction specifications. The cost estimates above estimate that permitting will be completed in 2019, and well engineering and construction costs will commence in 2019. Tampa Electric anticipates well construction will take approximately one year to complete.

After the test well is installed and reviewed, the company will proceed to obtain permanent deep well injection permits, convert the test well into a permanent deep injection well, and construct a second well. The deep well injection solution includes two permanent wells because a well must be available at all times for the Big Bend Station units’ FGD systems to operate, and operation of the FGD systems is an environmental requirement to run the generating units. In addition, when maintenance is needed on one of the deep injection wells, another well must be available in order to run the units.

O&M expenses will be incurred after the wells are in operation, with annual costs for 30 percent softening expected to be $1.9 million annually. The O&M expenses of the other treatment options under consideration are shown in the following table. The treatment option selected will depend on FDEP’s test well review and requirements for permanent well permits. These estimated annual costs may be revised due to timing of the work and will continue to be refined as design and engineering work progresses. Tampa Electric will provide updated cost estimates in its annual ECRC filings.

Total Capital and Annual O&M Costs

Deep Injection Wells with Various Pre-Treatment Options

	Capital Cost	Annual Operating Cost
	($000)	($000)
Deep well injection - with 30% softening	21,000	1,900
Deep well injection - with full softening	26,000	4,500
Deep well injection – with effluent blending	18,000	700

Q. Does this program qualify for cost recovery under the Commission's ECRC policies of the Gulf Order described earlier in your testimony?

A. Yes. Tampa Electric's Big Bend ELG Compliance Program qualifies for ECRC cost recovery under the Gulf Order. The costs of the program will be prudently incurred after April 13, 1993. The company's planned activities under the Big Bend ELG Compliance Program are essential components of the company's ability to comply with the EPA's legally required ELG Rule which was adopted and became effective after the company's last test year upon which rates are based. None of the costs proposed under the Big Bend ELG Compliance Program are recovered through some other cost recovery mechanism or through base rates.

Q. How should program costs be allocated?

A. This program is a compliance activity associated with limitations on wastewater discharge. Capital costs to implement the modified Big Bend ELG Compliance Program should be allocated to rate classes on a demand basis, and operation and maintenance costs should be allocated to rate classes on an energy basis. Estimated costs will be further refined during engineering work, and the project cost estimates will be updated in future filings with the Commission.

Q. Please summarize your testimony.

A. My testimony supports Commission approval for ECRC cost recovery purposes of Tampa Electric's Section 316(b) Impingement Mortality Project and its proposed Big Bend ELG Rule Compliance Program. Both programs meet the Commission's policy governing ECRC cost recovery as set forth in the Gulf Order. The costs of each program will be prudently incurred after April 13, 1993. The activities in these programs are legally required to comply with a governmentally imposed environmental regulation enacted, became effective, or whose effect was triggered after the company's last test year upon which rates are based. Finally, such costs are not recovered through some other cost recovery mechanism or through base rates.

Q. Does this conclude your testimony?

A. Yes, it does.