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March 2, 2018

-VIA ELECTRONIC FILING -

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

Re: Docket No. 20180001-EI

Dear Ms. Stauffer:

I enclose for electronic filing in the above docket (i) Florida Power & Light Company's ("FPL") Petition for Approval of Fuel Cost Recovery and Capacity Cost Recovery Net Final True-Ups for the Period Ending December 2017 and (ii) the prepared testimony and exhibits of FPL witnesses Renae B. Deaton and Gerard J. Yupp in support of the final true-ups.

Exhibit RBD-2 to Ms. Deaton's testimony and Exhibit GJY-1 to Mr. Yupp's testimony contain confidential information. This electronic filing includes only the redacted version of Exhibits RBD-2 and GJY-1. Contemporaneous herewith, FPL will file via hand-delivery a Request for Confidential Classification.

If there are any questions regarding this transmittal, please contact me at (561) 304-5795.

Sincerely,

s/ Maria J. Moncada
Maria J. Moncada

Enclosures
cc: Counsel for Parties of Record (w/encl.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor	Docket No: 20180001-EI Filed: March 2, 2018

PETITION FOR APPROVAL OF FUEL COST RECOVERY AND CAPACITY COST RECOVERY NET FINAL TRUE-UPS FOR THE PERIOD ENDING DECEMBER 2017, AND 2017 INCENTIVE MECHANISM RESULTS

Florida Power & Light Company ("FPL") hereby petitions this Commission for approval of (1) FPL's net Fuel and Purchased Power Cost Recovery ("FCR") final true-up amount of $23,632,267 under-recovery, (2) net Capacity Cost Recovery ("CCR") final true-up amount of $2,212,807 under-recovery, both for the period ending December 2017, and (3) FPL's retention and recovery of $2,317,099 of the $43,861,831 total 2017 Incentive Mechanism gains, representing 60% of the gains above $40 million threshold established in Order Nos. PSC-13-0023-S-EI and PSC-16-0560-AS-EI. FPL incorporates the prepared testimony and exhibits of FPL witnesses Renae B. Deaton and Gerard J. Yupp, and states as follows:

1. The $23,632,267 net FCR final true-up under-recovery for the period January 2017 through December 2017 was calculated in accordance with the methodology set forth in Schedule 1, page 2 of 2, attached to Order No. 10093, dated June 19, 1981. This calculation and the supporting documentation are contained in the prepared testimony and exhibits of Ms. Deaton.

2. By Order No. PSC-2018-0028-FOF-EI ("Order 2018-0028"), the Commission approved FCR Factors for the period commencing January 2018. These factors reflected an actual/estimated true-up over-recovery, including interest, for the period January 2017 through December 2017 of $45,572,897, which was also approved in Order 2018-0028. The actual over-

recovery, including interest, for the period January 2017 through December 2017 is $21,940,629. The $21,940,629 actual over-recovery, less the actual/estimated over-recovery of $45,572,897, results in a net FCR final true-up under-recovery of $23,632,267 that is to be included in the calculation of the FCR Factors for the period beginning January 2019.

3. The $2,212,807 net CCR final true-up under-recovery for the period January 2017 through December 2017 was calculated in accordance with the methodology set forth in Order No. 25773, dated February 24, 1992. This calculation and the supporting documentation are contained in the prepared testimony and exhibits of Ms. Deaton.

4. By Order 2018-0028, the Commission approved CCR Factors for the period commencing January 2018. These factors reflected an actual/estimated true-up under-recovery, including interest, for the period January 2017 through December 2017 of $6,649,359, which was also approved in Order 2018-0028. The actual under-recovery, including interest, for the period January 2017 through December 2017 is $8,862,166. The $8,862,166 actual under-recovery, less the actual/estimated under-recovery of $6,649,359, results in a net CCR final true-up under-recovery of $2,212,807 that is to be included in the calculation of the CCR Factors for the period beginning January 2019.

5. By Order No. PSC-13-0023-S-EI, issued January 14, 2013, in Docket No. 120015-EI, the Commission ordered that, as part of the fuel cost recovery clause, FPL annually file a final true-up schedule showing its gains in the prior calendar year on short-term wholesale sales, short-term wholesale purchases, and all forms of asset optimization ("Incentive Mechanism") it undertook in that calendar year. Additionally, Order No. PSC-16-0560-AS-EI, issued December 15, 2016, in Docket No. 160021-EI, approved the continuation of the Incentive Mechanism with certain modifications as discussed in the testimony of Mr. Yupp. Consistent with the orders, the results of its Incentive Mechanism for the period January 2017 through

December 2017 are provided in the testimony and exhibit of Mr. Yupp. The total gains for the Incentive Mechanism during that period were $43,861,831. This exceeded the sharing threshold of $40 million. Therefore, the incremental gains above $40 million are to be shared between customers and FPL, 40% and 60%, respectively. FPL's 60% share of the incremental gains above $40 million is $2,317,099, which is to be included in the calculation of the FCR Factors for the period beginning January 2019.

WHEREFORE, Florida Power & Light Company respectfully requests the Commission to approve for the period ending December 2017: (1) FPL's net FCR final true-up amount of $23,632,267 under-recovery and authorize the inclusion of this amount in the calculation of the FCR Factors for the period beginning January 2019, (2) FPL's net CCR final true-up amount of $2,212,807 under-recovery and authorize the inclusion of this amount in the calculation of the CCR Factors for the period beginning January 2019, and (3) FPL's retention and recovery of $2,317,099 of the $43,861,831 total 2017 Incentive Mechanism gains, representing 60% of the gains above $40 million, and authorize the inclusion of this amount in the calculation of the FCR Factors for the period beginning January 2019.

Respectfully submitted,

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By: *s/ Maria J. Moncada*
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CERTIFICATE OF SERVICE
Docket No. 20180001-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic service on this 2nd day of March 2018 to the following:

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By: *s/ Maria J. Moncada*
Maria J. Moncada

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RENAE B. DEATON

DOCKET NO. 20180001-EI

MARCH 2, 2018

Q. Please state your name, business address, employer and position.

A. My name is Renae B. Deaton. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408. I am employed by Florida Power & Light Company ("FPL" or "the Company") as the Director, Cost Recovery Clauses, in the Regulatory & State Governmental Affairs Department.

Q. Please state your education and business experience.

A. I hold a Bachelor of Science in Business Administration and a Master of Business Administration from Charleston Southern University. Since joining FPL in 1998, I have held various positions in the rates and regulatory areas. Prior to my current position, I held the positions of Senior Manager of Cost of Service and Load Research and Senior Manager of Rate Design in the Rates and Tariffs Department. I have previously testified before this Commission in base rate and clause recovery proceedings. I am a member of the Edison Electric Institute ("EEI") Rates and Regulatory Affairs Committee, and I have completed the EEI Advanced Rate Design Course. I have been a guest speaker at Public Utility Research Center/World Bank International Training Programs on Utility Regulation and Strategy. In 2016, I assumed my current position as Director, Cost Recovery Clauses, where I am responsible for providing direction as to appropriateness of inclusion of costs through a cost recovery clause and the overall preparation and filing of all cost recovery clause documents including testimony and discovery.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the schedules necessary to support the actual Fuel Cost Recovery ("FCR") Clause and Capacity Cost Recovery ("CCR") Clause net true-up amounts for the period January 2017 through December 2017.

The 2017 net true-up for the FCR Clause is an under-recovery, including interest, of $23,632,267. FPL is requesting Commission approval to include this FCR Clause true-up under-recovery of $23,632,267 in the calculation of the FCR factor for the period January 2019 through December 2019.

The 2017 net true-up for the CCR Clause is an under-recovery, including interest, of $2,212,807. FPL is requesting Commission approval to include this CCR Clause true-up under-recovery of $2,212,807 in the calculation of the CCR factors for the period January 2019 through December 2019.

Finally, FPL is requesting Commission approval to include $2,317,099 in the calculation of the FCR factors for the period January 2019 through December 2019, which represents FPL's share of the 2017 Incentive Mechanism gain described in the testimony of FPL witness Yupp.

Q. Have you prepared or caused to be prepared under your direction, supervision or control any exhibits in this proceeding?

A. Yes, I have. Exhibit RBD-1 contains the FCR related schedules and Exhibit RBD-2 contains the CCR related schedules. In addition, FCR Schedules A1 through A12 for the January 2017 through December 2017 period have been filed monthly with the Commission and served on all parties of record in this docket. Those schedules are incorporated herein by reference.

Q. What is the source of the data you present?

A. Unless otherwise indicated, the data are taken from the books and records of FPL. The books and records are kept in the regular course of the Company's business in accordance with generally accepted accounting principles and practices, and with the applicable provisions of the Uniform System of Accounts as prescribed by the Commission.

FUEL COST RECOVERY CLAUSE

Q. Please explain the calculation of the 2017 FCR net true-up amount.

A. Exhibit RBD-1, page 1, titled "Summary of Net True-Up," shows the calculation of the net true-up for the period January 2017 through December 2017, an under-recovery of $23,632,267.

The summary of the net true-up amount shows the actual end-of-period true-up over-recovery for the period January 2017 through December 2017 of

$21,940,629 on line 1. The actual/estimated true-up over-recovery for the same period of $45,572,897 is shown on line 2. Line 1 less line 2 results in the net final true-up under-recovery for the period January 2017 through December 2017 of $23,632,267 shown on line 3.

The calculation of the true-up amount for the period follows the procedures established by this Commission as set forth on Commission Schedule A2 "Calculation of True-Up and Interest Provision."

Q. Have you provided a schedule showing the calculation of the 2017 FCR actual true-up by month?

A. Yes. Exhibit RBD-1, page 2, titled "Calculation of Final True-up Amount," shows the calculation of the FCR actual true-up by month for January 2017 through December 2017.

Q. Have you provided schedules showing the variances between actual and actual/estimated FCR costs and applicable revenues for 2017?

A. Yes. Exhibit RBD-1, page 3, (sum of lines 44 and 45) compares the actual end-of-period true-up over-recovery of $21,940,629 (column 3) to the actual/estimated end-of-period true-up over-recovery of $45,572,897 (column 4) resulting in a net under-recovery of $23,632,267 (column 5). Exhibit RBD-1, page 3 lines 43 and 34, shows that the variance consists of an increase in jurisdictional costs of $42.4 million partially offset by an increase in revenues of $18.9 million.

Q. Please summarize the variance schedule on page 3 of Exhibit RBD-1.

A. FPL previously projected jurisdictional total fuel costs and net power transactions to be $2.939 billion for 2017 (Exhibit RBD-1, page 3, line 43, column 4). The actual jurisdictional total fuel costs and net power transactions for that period is $2.981 billion (Exhibit RBD-1, page 3, line 43, column 3). Jurisdictional total fuel costs and net power transactions are $42.4 million, or 1.4% higher than previously projected (Exhibit RBD-1, page 3, line 43, column 5) and jurisdictional fuel revenues, net of revenue taxes for 2017 are $18.9 million, or 0.6% higher than previously projected (Exhibit RBD-1, page 3, line 34, column 5).

Q. Please explain the variances in jurisdictional total fuel costs and net power transactions.

A. Below are the primary reasons for the $42.4 million variance.

<u>Fuel Cost of System Net Generation: $69.8 million increase (Exhibit RBD-1, page 3, line 2, column 5)</u>

The table below provides the detail of this variance.

Fuel Variance	2017 FINAL TRUE-UP	2017 ACTUAL/ ESTIMATED	DIFFERENCE
Heavy Oil			
Total Dollar	$24,618,491	$13,934,673	$10,683,819
Units (MMbtu)	2,060,902	1,185,043	875,859
$ per Units	11.9455	11.7588	0.1867
Variance Due to Consumption			$10,299,035
Variance Due to Cost			$384,783
Total Variance			$10,683,819

Fuel Variance	2017 FINAL TRUE-UP	2017 ACTUAL/ ESTIMATED	DIFFERENCE
Light Oil			
Total Dollar	$38,351,438	$34,663,972	$3,687,467
Units (MMbtu)	2,080,525	1,880,620	199,905
$ per Units	18.4335	18.4322	0.0013
Variance Due to Consumption			$3,684,693
Variance Due to Cost			$2,774
Total Variance			$3,687,467
Coal			
Total Dollar	$124,990,904	$120,910,198	$4,080,706
Units (MMbtu)	45,741,719	44,990,624	751,095
$ per Units	2.7325	2.6875	0.0451
Variance Due to Consumption			$2,018,533
Variance Due to Cost			$2,062,173
Total Variance			$4,080,706
Gas			
Total Dollar	$2,713,130,934	$2,657,374,216	$55,756,719
Units (MMbtu)	633,859,434	611,518,799	22,340,635
$ per Units	4.2803	4.3455	(0.0652)
Variance Due to Consumption			$97,081,934
Variance Due to Cost			($41,325,215)
Total Variance			$55,756,719
Nuclear			
Total Dollar	$189,997,758	$194,420,124	($4,422,366)
Units (MMbtu)	307,203,081	307,982,598	(779,517)
$ per Units	0.6185	0.6313	(0.0128)
Variance Due to Consumption			($492,086)
Variance Due to Cost			($3,930,280)
Total Variance			($4,422,366)
Total			
Variance Due to Consumption			$112,592,110
Variance Due to Cost			($42,805,766)
Total Variance			$69,786,344

Fuel Cost of Power Sold: $3.5 million decrease (Exhibit RBD-1, page 3, line 6, column 5)

The variance for the fuel cost of power sold is primarily attributable to lower than projected fuel costs attributable to economy sales. The average unit fuel cost on economy power sales was $2.29/MWh lower than projected, resulting in a cost decrease of $4.5 million. This variance was partially offset by higher than projected economy sales. FPL sold 1,963,107 MWh or 39,777 MWh more of economy power, resulting in an increase of $1.0 million. The combination of lower fuel costs attributable to economy power sales and higher economy power sales resulted in a net decrease of $3.5 million.

Energy Cost of Economy Purchases: $15.9 million decrease (Exhibit RBD-1, page 3, line 10, column 5)

The variance for the energy cost of economy purchases is primarily attributable to lower than projected economy purchases. FPL purchased 621,439 MWh, or 636,820 MWh less of economy power resulting in a volume decrease of $20.7 million. This volume decrease was partially offset by higher than projected costs for economy power. The average cost of economy purchases was $7.85/MWh higher than projected, resulting in a cost increase of $4.9 million. The combination of lower economy purchases coupled with higher costs for economy purchases resulted in a net decrease of $15.9 million.

Energy Payments to Qualifying Facilities: $4.1 million decrease (Exhibit RBD-1, page 3, line 9, column 5)

The variance for energy payments to qualifying facilities is primarily attributable to lower than projected purchases and costs from As-Available Co-Generation facilities. In total, FPL purchased 208,463 MWh, or 177,990 MWh less than projected from As-Available Co-Generation facilities at an average unit fuel cost that was $1.60/MWh lower than projected. The combination of lower As-Available purchases and lower fuel costs resulted in a decrease of $3.9 million. The remaining decrease of $0.1 million was attributable to lower than projected fuel costs from FPL's Firm Co-Generation facility, partially offset by higher than projected purchases of Firm Co-Generation power.

Gains from Off-System Sales: $1.9 million increase (Exhibit RBD-1, page 3, line 7, column 5)

The variance for gains from off-system sales is attributable to a higher than projected volume of economy sales coupled with higher than projected margins on those sales. FPL sold 1,963,107 MWh, or 39,777 MWh more of economy power than previously projected, resulting in an increase of $0.3 million. In addition, the margin on economy sales averaged $0.82/MWh more than projected, which resulted in an increase of $1.6 million. The larger volume and higher margin associated with the economy sales resulted in a total increase for gains from off-system sales of $1.9 million.

Q. What was the variance in retail (jurisdictional) FCR revenues?

A. As shown on Exhibit RBD-1, page 3, line 34, actual 2017 jurisdictional FCR revenues, net of revenue taxes, were approximately $18.9 million higher than the actual/estimated projection. This was primarily due to jurisdictional sales that were 366,044 MWh higher than the actual/estimated projection.

Q. FPL witness Yupp calculates in his testimony that FPL is entitled to retain $2,317,099 as its 60% share of 2017 Incentive Mechanism gains over the $40 million threshold. When is FPL requesting to recover its share of the gains, and how will this be reflected in the FCR schedules?

A. FPL is requesting recovery of its share of the 2017 Incentive Mechanism gains through the 2019 FCR factors, consistent with how gains have been recovered in prior years. FPL will include the approved jurisdictionalized Incentive Mechanism gains amount in the calculation of the 2019 FCR factors and will reflect recovery of one-twelfth of the approved amount, net of revenue taxes, in each month's Schedule A2 for the period January 2019 through December 2019 as a reduction to jurisdictional fuel revenues applicable to each period.

CAPACITY COST RECOVERY CLAUSE

Q. Please explain the calculation of the 2017 CCR net true-up amount.

A. Exhibit RBD-2, page 1, titled "Final True-Up Summary" shows the calculation of the CCR net true-up for the period January 2017 through December 2017, an under-recovery of $2,212,807, which FPL is requesting to be included in the calculation of the CCR factors for the January 2019 through December 2019 period.

The actual end-of-period under-recovery for the period January 2017 through December 2017 of $8,862,166 shown on line 1 less the actual/estimated end-of-period under-recovery for the same period of $6,649,359 shown on line 2 that was approved by the Commission in Order No. PSC-2018-0028-FOF-EI, results in the net true-up under-recovery for the period January 2017 through December 2017 of $2,212,807 shown on line 3.

Q. Have you provided a schedule showing the calculation of the 2017 CCR actual true-up by month?

A. Yes. Exhibit RBD-2, page 2, titled "Calculation of Final True-up" shows the calculation of the CCR end-of-period true-up for the period January 2017 through December 2017 by month.

Q. Is this true-up calculation consistent with the true-up methodology used for the FCR Clause?

A. Yes, it is. The calculation of the true-up amount follows the procedures established by this Commission set forth on Commission Schedule A2 "Calculation of True-Up and Interest Provision" for the FCR Clause.

Q. Have you provided a schedule showing the variances between actual and actual/estimated capacity charges and applicable revenues for 2017?

A. Yes. Exhibit RBD-2, page 3, titled "Calculation of Final True-up Variances," shows the actual capacity charges and applicable revenues compared to actual/estimated capacity charges and applicable revenues for the period January 2017 through December 2017.

Q. Please explain the variances related to capacity costs.

A. As shown in Exhibit RBD-2, page 3, line 17, column 5, the variance related to jurisdictional capacity costs is a decrease of $5.3 million, or 1.7%, from the actual/estimated projection. The primary reason for this variance is a $5.6 million or 1.7% decrease in total system capacity costs (page 3, line 14, column 5).

Below are the primary reasons for the $5.6 million decrease in total system capacity costs.

<u>Incremental Plant Security Costs - O&M: $3.6 million decrease (Exhibit RBD-2, page 3, line 8, column 5)</u>

The variance for incremental plant security costs - O&M is primarily attributable to the implementation of cost savings initiatives at the St. Lucie and Turkey Point plants resulting in lower security force costs. Additionally, NRC Homeland Security Fees and cyber security costs were lower than estimated.

<u>Payments to Non-Cogenerators: $2.1 million decrease (Exhibit RBD-2, page 3, line 1, column 5)</u>

The variance for payments to non-cogenerators (SJRPP and SWA) is primarily attributable to lower than projected costs associated with O&M and inventory of $2.8 million and property taxes of $0.14 million. Additionally, slightly lower than projected costs associated with the SWA agreement resulted in a decrease of approximately $0.14 million. This was partially offset by an increase in costs of approximately $1.0 million related to SJRPP for Cumulative Capital Recovery Amount payments.

<u>Incremental Nuclear NRC Compliance Costs (Fukushima): O&M - $0.9 million increase (Exhibit RBD-2, page 3, line 10, column 5)</u>

The variance for incremental NRC compliance O&M costs is primarily attributable to the NRC flooding analysis for flood doors that was previously projected as capital but later determined to be O&M and booked as such.

Q. Please describe the variance in CCR revenues.

A. As shown on page 3, line 22, column 5, actual CCR revenues (net of revenue taxes), were $7,519,744 lower than projected in the actual/estimated true-up filing. This was primarily due to the adjustment for recovery of base non-fuel revenue requirements associated with the Indiantown transaction. As discussed in my 2017 actual/estimated true-up testimony in Docket 20170001-EI, this adjustment was not included in the calculation of the 2017 CCR factor because the transaction had not yet been approved at the time of FPL's 2017 projection filing. The adjustment was partially offset by higher than projected jurisdictional sales, which were 366,044 MWh higher than the actual/estimated projection.

Q. Have you provided a schedule showing the actual monthly capacity payments by contract?

A. Yes. Schedule A12 consists of two pages that are included in Exhibit RBD-2 as pages 4 and 5. Page 4 shows the actual capacity payments for FPL's Purchase Power Agreements for the period January 2017 through December 2017. Page 5 provides the Short Term Capacity Payments for the period January 2017 through December 2017.

Q. Have you provided a schedule showing the capital structure components and cost rates relied upon by FPL to calculate the rate of return applied to all capital projects recovered through the FCR and CCR Clauses?

A. Yes. The capital structure components and cost rates used to calculate the rate of return on the capital investments for the period January 2017 through December 2017 are included on pages 11 and 12 of Exhibit RBD-2.

Q. Does this conclude your testimony?

A. Yes, it does.

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SUMMARY OF NET TRUE-UP

FOR THE PERIOD: JANUARY 2017 THROUGH DECEMBER 2017

	Total
1. End of Period True-up [1]	$21,940,629
2. Less: Actual Estimated True-up for the same period [2]	$45,572,897
3. Net True-up for the period	($23,632,267)

[1] Page 2, Column 15, Lines 44 & 45.
[2] Approved in FPSC Final Order PSC-2018-0028-FOF-EI.

Note: Totals may not add due to rounding.

( ) Reflects Underrecovery

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD: JANUARY 2017 THROUGH DECEMBER 2017

SCHEDULE: E1-B

Docket No. 20180001-EI
2017 FCR Final True Up
Exhibit RBD-1, Page 2 of 3

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.		January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	12 Month Period
1	**Fuel Costs & Net Power Transactions**													
2	Fuel Cost of System Net Generation (Per A3) (1)	$225,985,792	$198,798,977	$222,691,303	$242,121,494	$272,848,707	$278,075,700	$311,180,119	$317,099,500	$282,643,014	$281,225,368	$229,526,015	$228,891,026	$3,091,087,016
3	Fuel Cost of Stratified Sales	($196,821)	($913,951)	($361,826)	($93,524)	($2,085,355)	($2,860,176)	($2,253,496)	($2,626,180)	($2,907,661)	($2,286,024)	($1,704,952)	($796,736)	($19,086,704)
4	Scherer Coal Cars Depreciation & Return (Per A2)	($0)	($0)	($0)	($0)	($30)	$0	$0	$0	$0	$0	$0	($53,218)	($53,249)
5	Rail Car Lease (Cedar Bay/ICL)	$315,790	$170,925	$171,407	$196,244	$235,509	$227,817	$212,823	$211,416	$306,615	$292,888	$288,324	$263,790	$2,893,548
6	Fuel Cost of Power Sold (Per A6)	($12,097,683)	($9,794,312)	($5,961,454)	($3,235,840)	($1,589,425)	($1,584,749)	($1,547,330)	($1,300,939)	($2,012,412)	($2,084,414)	($2,682,642)	($4,800,936)	($48,692,136)
7	Gains from Off-System Sales (Per A6)	($4,073,624)	($3,099,715)	($1,697,456)	($920,259)	($521,832)	($652,982)	($464,488)	($443,186)	($932,734)	($464,241)	($877,409)	($2,182,494)	($16,330,420)
8	Fuel Cost of Purchased Power (Per A7)	$6,972,270	$4,923,858	$5,367,713	$8,343,427	$9,777,949	$9,105,356	$8,653,532	$10,562,779	$8,764,789	$8,985,142	$6,169,666	$4,058,719	$91,685,199
9	Energy Payments to Qualifying Facilities (Per A8)	$958,553	($2,405,192)	$419,499	$382,391	$309,534	$280,091	$286,062	$366,705	$391,953	$441,363	$324,188	$472,857	$2,228,003
10	Energy Cost of Economy Purchases (Per A9)	$1,275	$190,215	$571,934	$2,521,941	$5,873,445	$5,867,827	$2,362,494	$5,062,057	$1,556,346	$1,035,509	$74,870	$0	$25,117,914
11	Total Fuel Costs & Net Power Transactions	$217,865,552	$187,870,805	$221,201,120	$249,315,873	$284,848,502	$288,458,884	$318,429,717	$328,932,151	$287,809,909	$287,145,591	$231,118,060	$225,853,007	$3,128,849,170
12														
13	**Incremental Optimization Costs**													
14	Incremental Personnel, Software, and Hardware Costs (Per A2)	$34,985	$41,722	$42,934	$37,958	$42,276	$263,220	$40,363	$40,958	$35,070	$39,721	$39,749	$44,966	$703,923
15	Variable Power Plant O&M Attributable to Off-System Sales (Per A6)	$333,351	$280,600	$166,096	$77,387	$25,767	$36,058	$29,537	$25,860	$35,279	$40,765	$73,640	$151,227	$1,275,568
16	Variable Power Plant O&M Avoided due to Economy Purchases (Per A9)	$0	($4,343)	($12,046)	($44,359)	($100,260)	($97,285)	($32,616)	($73,554)	($24,879)	($13,019)	($1,518)	$0	($403,880)
17	Total	$368,336	$317,980	$196,984	$70,985	($32,217)	$201,993	$37,283	($6,736)	$45,470	$67,468	$111,871	$196,193	$1,575,612
18														
19	Dodd Frank Fees	$375	$375	$375	$375	$375	$0	$0	$750	$0	$0	$0	$0	$2,625
20														
21	**Adjustments to Fuel Cost**													
22	Energy Imbalance Fuel Revenues	($16,979)	($48,603)	($40,728)	($63,551)	($97,286)	$815	($48,702)	($158,084)	($83,391)	($30,268)	($73,400)	($65,631)	($725,808)
23	Inventory Adjustments	$128,216	$55,389	($651,667)	$97,636	$114,141	$36,557	($115,711)	$211,700	($132,010)	($178,748)	$813,053	($35,970)	$342,586
24	Non Recoverable Oil/Tank Bottoms	$0	$0	$0	($5,842)	$0	$18,697	$0	$0	$0	$0	$223,244	$0	$236,099
25	Other O&M Expense (5)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$504,195	$504,195
26	Adjusted Total Fuel Costs & Net Power Transactions	$218,345,500	$188,195,945	$220,706,085	$249,415,476	$284,833,515	$288,716,947	$318,302,587	$328,979,781	$287,639,977	$287,004,043	$232,192,828	$226,451,794	$3,130,784,478
27	**Jurisdictional kWh Sales**													
28	Jurisdictional kWh Sales	8,348,026,806	7,111,076,501	7,490,831,223	8,227,142,053	9,287,223,926	10,296,705,096	10,858,076,567	10,775,774,598	10,321,003,966	9,816,163,272	8,327,131,391	8,011,807,960	108,870,963,359
29	Sales for Resale (excluding Stratified Sales)	420,790,768	416,474,025	378,655,147	425,729,774	456,403,475	524,960,605	514,343,095	575,559,850	586,687,829	466,814,557	481,288,449	392,956,751	5,640,664,325
30	Sub-Total Sales	8,768,817,574	7,527,550,526	7,869,486,370	8,652,871,827	9,743,627,401	10,821,665,701	11,372,419,662	11,351,334,448	10,907,691,795	10,282,977,829	8,808,419,840	8,404,764,711	114,511,627,684
31														
32	**Jurisdictional % of Total Sales (Line 28/30)**	95.20128%	94.46734%	95.18831%	95.07990%	95.31588%	95.14899%	95.47728%	94.92958%	94.62134%	95.46032%	94.53604%	95.32460%	95.07416%
33	**True-up Calculation**													
34	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$231,334,261	$194,527,572	$205,804,680	$227,694,257	$260,867,553	$292,323,443	$310,463,835	$307,864,385	$293,845,761	$277,377,907	$231,072,369	$221,414,728	$3,054,590,752
35	**Fuel Adjustment Revenues Not Applicable to Period**													
36	Prior Period True-up (Collected)/Refunded This Period (2)	($2,206,974)	($2,206,974)	($2,206,974)	($2,206,974)	($2,206,974)	($2,206,974)	($2,206,974)	($2,206,974)	($2,206,974)	($2,206,974)	($2,206,974)	($2,206,974)	($26,483,684)
37	GPIF, Net of Revenue Taxes (3)	($2,636,272)	($2,636,272)	($2,636,272)	($2,636,272)	($2,636,272)	($2,636,272)	($2,636,272)	($2,636,272)	($2,636,272)	($2,636,272)	($2,636,272)	($2,636,272)	($31,635,265)
38	Vendor Settlement Refund per Order No. PSC-16-0298-FOF-EI	$631,160	$631,160	$631,160	$631,160	$631,160	$631,160	$631,160	$631,160	$631,160	$631,160	$631,160	$631,160	$7,573,924
39	Incentive Mechanism Collection (6)	($41,708)	($41,708)	($41,708)	($41,708)	($41,708)	($41,708)	($41,708)	($41,708)	($41,708)	($41,708)	($41,708)	($41,708)	($500,500)
40	Jurisdictional Fuel Revenues Applicable to Period	$227,080,467	$190,273,778	$201,550,886	$223,440,464	$256,613,759	$288,069,650	$306,210,041	$303,610,591	$289,591,967	$273,124,113	$226,818,575	$217,160,934	$3,003,545,226
41	Adjusted Total Fuel Costs & Net Power Transactions	$218,345,500	$188,195,945	$220,706,085	$249,415,476	$284,833,515	$288,716,947	$318,302,587	$328,979,781	$287,639,977	$287,004,043	$232,192,828	$226,451,794	$3,130,784,478
42	Jurisdictional Sales % of Total kWh Sales (Line 32)	95.20128%	94.46734%	95.18831%	95.07990%	95.31588%	95.14899%	95.47728%	94.92958%	94.62134%	95.46032%	94.53604%	95.32460%	95.07416%
43	Juris. Total Fuel Costs & Net Power Trans. (Line 41xLine42x1.00153)	$208,185,748	$178,055,712	$210,407,825	$237,506,815	$271,906,953	$275,131,567	$304,371,630	$312,776,942	$272,585,219	$274,394,159	$219,841,749	$216,194,539	$2,981,358,859
44	True-up Provision for the Month - Over/(Under) Recovery (Line 40 - Line 43)	$18,894,719	$12,218,066	($8,856,938)	($14,066,351)	($15,293,194)	$12,938,083	$1,838,411	($9,166,351)	$17,006,748	($1,270,046)	$6,976,826	$966,395	$22,186,367
45	Interest Provision for the Month	($22,785)	($11,699)	($11,258)	($20,249)	($30,259)	($33,625)	($28,255)	($29,921)	($20,491)	($14,064)	($13,578)	($9,553)	($245,737)
46	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	($26,483,684)	($5,404,776)	$9,008,565	$2,347,342	($9,532,284)	($22,648,763)	($7,537,333)	($3,520,203)	($10,509,501)	$8,683,729	$9,606,593	$18,776,814	($26,483,684)
47	Vendor Settlement Refund	$7,573,924	$6,942,764	$6,311,603	$5,680,443	$5,049,283	$4,418,122	$3,786,962	$3,155,802	$2,524,641	$1,893,481	$1,262,321	$631,160	$7,573,924
48	Deferred True-up Beginning of Period - Over/(Under) Recovery (4)	($28,780,519)	($28,780,519)	($28,780,519)	($28,780,519)	($28,780,519)	($28,780,519)	($28,780,519)	($28,780,519)	($28,780,519)	($28,780,519)	($28,780,519)	($28,780,519)	($28,780,519)
49	Prior Period True-up Collected/(Refunded) This Period (2)	$2,206,974	$2,206,974	$2,206,974	$2,206,974	$2,206,974	$2,206,974	$2,206,974	$2,206,974	$2,206,974	$2,206,974	$2,206,974	$2,206,974	$26,483,684
50	Vendor Settlement Refund Per Order No. PSC-16-0298-FOF-EI	($631,160)	($631,160)	($631,160)	($631,160)	($631,160)	($631,160)	($631,160)	($631,160)	($631,160)	($631,160)	($631,160)	($631,160)	($7,573,924)
51	End of Period Net True-up Amount Over/(Under) Recovery (Lines 44 through 50)	($27,242,532)	($13,460,351)	($20,752,734)	($33,263,520)	($47,011,160)	($32,530,890)	($29,144,920)	($36,765,379)	($18,203,309)	($17,911,606)	($9,372,545)	($6,839,889)	($6,839,889)
52														

53 (1) Actuals include various adjustments as noted on the A-Schedules.
54 (2) Prior Period 2016 Actual/Estimated True-up.
55 (3) Generation Performance Incentive Factor is (($31,658,059/12) x 99.9280%) - See Order No. PSC-2016-0547-FOF-EI.
56 (4) 2016 Final True-up.
57 (5) Other O&M expense reflects charges related to annual nuclear fuel design software maintenance which were originally recorded to nuclear fuel and amortized through Fuel Cost of Net Generation.
58 Due to this change in accounting treatment, these charges are now being recorded as O&M and expensed in the month incurred, with the amounts previously amortized returned to customers over the remainder of the amortization period.
59 (6) Jurisdictionalized Incentive Mechanism - FPL Portion is (($500,861/12) x 99.9280%) - See Order No. PSC-2016-0547-FOF-EI

Note: Amounts may not agree to A-Schedules due to rounding.

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
FOR THE PERIOD: JANUARY 2017 THROUGH DECEMBER 2017

(1)	(2)	(3)	(4)	(5)	(6)
Line No.		FCR - 2017 Final True-up	FCR - 2017 Actual Estimated	Dif. FCR - 2017 Actual Estimated	% Dif. FCR - 2017 Actual Estimated
1	**Fuel Costs & Net Power Transactions**				
2	Fuel Cost of System Net Generation (Per A3) [1]	$3,091,087,016	$3,021,300,669	$69,786,346	2.3%
3	Fuel Cost of Stratified Sales	($19,086,704)	($20,982,572)	$1,895,868	(9.0%)
4	Scherer Coal Cars Depreciation & Return (Per A2)	($53,249)	($31)	($53,218)	171,449.7%
5	Rail Car Lease (Cedar Bay/ICL)	$2,893,548	$3,164,987	($271,439)	(8.6%)
6	Fuel Cost of Power Sold (Per A6)	($48,692,136)	($52,178,413)	$3,486,277	(6.7%)
7	Gains from Off-System Sales (Per A6)	($16,330,420)	($14,423,869)	($1,906,551)	13.2%
8	Fuel Cost of Purchased Power (Per A7)	$91,685,199	$91,697,791	($12,592)	(0.0%)
9	Energy Payments to Qualifying Facilities (Per A8)	$2,228,003	$6,296,255	($4,068,252)	(64.6%)
10	Energy Cost of Economy Purchases (Per A9)	$25,117,914	$40,980,737	($15,862,823)	(38.7%)
11	Total Fuel Costs & Net Power Transactions	$3,128,849,170	$3,075,855,555	$52,993,616	1.7%
12					
13	**Incremental Optimization Costs**				
14	Incremental Personnel, Software, and Hardware Costs (Per A2)	$703,923	$701,442	$2,481	0.4%
15	Variable Power Plant O&M Attributable to Off-System Sales (Per A6)	$1,275,568	$1,250,109	$25,459	2.0%
16	Variable Power Plant O&M Avoided due to Economy Purchases (Per A9)	($403,880)	($817,813)	$413,933	(50.6%)
17	Total	$1,575,612	$1,133,738	$441,874	39.0%
18					
19	Dodd Frank Fees	$2,625	$4,500	($1,875)	(41.7%)
20					
21	**Adjustments to Fuel Cost**				
22	Energy Imbalance Fuel Revenues	($725,808)	($266,332)	($459,476)	172.5%
23	Inventory Adjustments	$342,586	($219,728)	$562,314	(255.9%)
24	Non Recoverable Oil/Tank Bottoms	$236,099	$12,855	$223,244	1,736.6%
25	Other O&M Expense [5]	$504,195	$0	$504,195	N/A
26	Adjusted Total Fuel Costs & Net Power Transactions	$3,130,784,478	$3,076,520,587	$54,263,891	1.8%
27	**Jurisdictional kWh Sales**				
28	Jurisdictional kWh Sales	108,870,963,359	108,504,918,871	366,044,488	0.3%
29	Sales for Resale (excluding Stratified Sales)	5,640,664,325	5,260,182,859	380,481,466	7.2%
30	Sub-Total Sales	114,511,627,684	113,765,101,730	746,525,954	0.7%
31					
32	**Jurisdictional % of Total Sales (Line 28/30)**	N/A	N/A	N/A	N/A
33	**True-up Calculation**				
34	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$3,054,590,752	$3,035,718,525	$18,872,226	0.6%
35	**Fuel Adjustment Revenues Not Applicable to Period**				
36	Prior Period True-up (Collected)/Refunded This Period [2]	($26,483,684)	($26,483,684)	($0)	0.0%
37	GPIF, Net of Revenue Taxes [3]	($31,635,265)	($31,635,266)	$0	(0.0%)
38	Vendor Settlement Refund per Order No. PSC-16-0298-FOF-EI	$7,573,924	$7,573,924	($0)	(0.0%)
39	Incentive Mechanism Collection [6]	($500,500)	($500,501)	$0	(0.0%)
40	Jurisdictional Fuel Revenues Applicable to Period	$3,003,545,226	$2,984,672,999	$18,872,227	0.6%
41	Adjusted Total Fuel Costs & Net Power Transactions	$3,130,784,478	$3,076,520,587	$54,263,891	1.8%
42	Jurisdictional Sales % of Total kWh Sales (Line 32)	N/A	N/A	N/A	N/A
43	Juris. Total Fuel Costs & Net Power Trans. (Line 41xLine42x1.00153)	$2,981,358,859	$2,938,918,728	$42,440,132	1.4%
44	True-up Provision for the Month - Over/(Under) Recovery (Line 40 - Line 43)	$22,186,367	$45,754,271	($23,567,905)	(51.5%)
45	Interest Provision for the Month	($245,737)	($181,375)	($64,363)	35.5%
46	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	($26,483,684)	($26,483,684)	$0	0.0%
47	Vendor Settlement Refund	$7,573,924	$7,573,924	$0	0.0%
48	Deferred True-up Beginning of Period - Over/(Under) Recovery [4]	($28,780,519)	($28,780,519)	$0	0.0%
49	Prior Period True-up Collected/(Refunded) This Period [2]	$26,483,684	$26,483,684	$0	0.0%
50	Vendor Settlement Refund Per Order No. PSC-16-0298-FOF-EI	($7,573,924)	($7,573,924)	$0	(0.0%)
51	End of Period Net True-up Amount Over/(Under) Recovery (Lines 44 through 50)	($6,839,889)	$16,792,378	($23,632,267)	(140.7%)
52					

53 [1] Actuals include various adjustments as noted on the A-Schedules.

54 [2] Prior Period 2016 Actual/Estimated True-up.

55 [3] Generation Performance Incentive Factor is (($31,658,059/12) x 99.9280%) - See Order No. PSC-2016-0547-FOF-EI.

56 [4] 2016 Final True-up.

57 [5] Other O&M expense reflects charges related to annual nuclear fuel design software maintenance which were originally recorded to nuclear fuel and amortized through Fuel Cost of Net Generation.

58 Due to this change in accounting treatment, these charges are now being recorded as O&M and expensed in the month incurred, with the amounts previously amortized returned to customers over the remainder of the amortization period.

59 [6] Jurisdictionalized Incentive Mechanism - FPL Portion is (($500,861/12) x 99.9280%) - See Order No. PSC-2016-0547-FOF-EI

Note: Amounts may not agree to A-Schedules due to rounding.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
FINAL TRUE-UP SUMMARY
FOR THE PERIOD: JANUARY 2017 THROUGH DECEMBER 2017

Line No.	Line	Total
1	End of Period True-Up for the Period	($8,862,166)
2	True Up Provision for Month Act/Est	($6,649,359)
3	Net True Up for the Period	($2,212,807)
4		
5	(1) From Page 2, Column 15, Lines 24 & 25.	
6	(2) Approved in FPSC Final Order PSC-2018-0028-FOF-EI.	
7		
8	Note: Totals may not add due to rounding	
9		
10	( ) Reflects Under-recovery	
11		
12		
13		

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP
FOR THE PERIOD JANUARY 2017 THROUGH DECEMBER 2017

(1) Line No.	(2) CCR True Up Line	(3) a-Jan - 2017	(4) a-Feb - 2017	(5) a-Mar - 2017	(6) a-Apr - 2017	(7) a-May - 2017	(8) a-Jun - 2017	(9) a-Jul - 2017	(10) a-Aug - 2017	(11) a-Sep - 2017	(12) a-Oct - 2017	(13) a-Nov - 2017	(14) a-Dec - 2017	(15) 2017
1	Payments to Non-cogenerators	$5,766,501	$6,108,331	$7,331,333	$6,885,779	$7,218,840	$5,809,218	$6,018,687	$5,728,777	$6,303,387	$5,270,026	$4,872,922	$4,672,896	$71,986,698
2	Payments to Co-generators	$1,331,163	$100,995	$110,082	$110,600	$110,600	$110,600	$110,600	$110,600	$110,600	$110,600	$110,600	$110,600	$2,537,640
3	Cedar Bay Transaction - Reg Asset - Amort & Return	$10,973,761	$10,938,076	$10,902,391	$10,866,707	$10,831,022	$10,795,337	$10,753,505	$10,717,889	$10,682,273	$10,646,656	$10,611,040	$10,575,424	$129,294,081
4	Cedar Bay Transaction - Reg Liability - Amort & Return	($105,503)	($105,036)	($104,568)	($104,101)	($103,634)	($103,166)	($102,618)	($102,152)	($101,685)	($101,219)	($100,753)	($100,286)	($1,234,722)
5	Indiantown Transaction - Regulatory Asset - Amortization and Return	$7,631,397	$7,599,296	$7,567,195	$7,535,095	$7,502,994	$7,470,893	$7,432,522	$7,400,483	$7,368,443	$7,336,404	$7,304,365	$7,272,326	$89,421,413
6	SJRPP Suspension Accrual	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($9,083,880)
7	Return on SJRPP Suspension Liability	($142,899)	($137,086)	($131,273)	($125,461)	($119,648)	($113,836)	($107,815)	($102,014)	($96,212)	($90,411)	($84,609)	($78,808)	($1,330,072)
8	Incremental Plant Security Costs-Order No. PSC-02-1761 (O&M)	$2,841,275	$2,809,492	$2,958,940	$3,129,535	$2,907,157	$2,285,473	$2,914,223	$2,637,225	$2,186,964	$3,419,066	$2,985,400	$4,261,267	$35,336,018
9	Incremental Plant Security Costs-Order No. PSC-02-1761 (Capital)	$196,277	$197,221	$199,137	$202,857	$203,171	$205,075	$216,405	$227,835	$236,645	$244,281	$251,099	$289,239	$2,669,243
10	Incremental Nuclear NRC Compliance Costs O&M	$33,582	$62,929	$70,128	$68,320	$140,764	$139,240	$79,917	$189,986	$47,484	$1,177,870	$313,020	$100,280	$2,423,522
11	Incremental Nuclear NRC Compliance Costs Capital	$952,140	$949,623	$953,504	$968,137	$977,055	$975,766	$972,308	$969,300	$966,893	$976,753	$997,462	$1,012,901	$11,671,842
12	Transmission of Electricity by Others	$1,866	$6,199	$35,501	$234	($347)	$886,609	$44,402	$2,473	$24,961	($197,031)	($10)	$19,200	$824,059
13	Transmission Revenues from Capacity Sales	($1,174,833)	($1,041,797)	($756,537)	($404,919)	($568,743)	($535,399)	($459,879)	($399,410)	($595,189)	($361,021)	($373,085)	($657,478)	($7,328,291)
14	Total (Lines 1 through 13)	27,547,737	26,731,254	28,378,842	28,375,791	28,342,241	27,168,821	27,115,268	26,624,002	26,377,575	27,674,984	26,130,463	26,720,573	327,187,550
15														
16	Jurisdictional Separation Factor [1]	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	N/A
17	Jurisdictional Capacity Charges	26,183,182	25,407,142	26,973,119	26,970,219	26,938,330	25,823,035	25,772,135	25,305,204	25,070,983	26,304,126	24,836,111	25,396,991	310,980,577
18														
19	CCR Revenues	$21,596,164	$19,083,528	$19,898,751	$21,654,416	$24,189,774	$26,435,698	$27,904,253	$27,946,136	$27,202,220	$25,792,295	$21,951,778	$20,942,027	$284,597,039
20	Prior Period True-up Provision	$1,298,228	$1,298,228	$1,298,228	$1,298,228	$1,298,228	$1,298,228	$1,298,228	$1,298,228	$1,298,228	$1,298,228	$1,298,228	$1,298,228	$15,578,733
21	Cape Canaveral GBRA Refund	$157,544	$157,544	$157,544	$157,544	$157,544	$157,544	$157,544	$157,544	$157,544	$157,544	$157,544	$157,544	$1,890,528
22	CCR Revenues Applicable to Curr Pd (Net of Revenue Taxes)	23,051,936	20,539,300	21,354,523	23,110,188	25,645,545	27,891,470	29,360,024	29,401,907	28,657,992	27,248,067	23,407,550	22,397,799	302,066,300
23														
24	True-up Provision for Month - Over/(Under) Recovery (Line 22 - Line 17)	($3,131,246)	($4,867,843)	($5,618,596)	($3,860,031)	($1,292,785)	$2,068,435	$3,587,890	$4,096,704	$3,587,009	$943,941	($1,428,562)	($2,999,192)	($8,914,277)
25	Interest Provision for the Month	$13,846	$9,959	$6,999	$3,333	$313	($552)	$659	$2,821	$4,098	$4,916	$4,596	$1,121	$52,111
26	True-up & Interest Provision BOM - Over/(Under) Recovery	$17,469,261	$12,896,089	$6,582,434	($484,934)	($5,797,404)	($8,545,648)	($7,933,537)	($5,800,760)	($3,157,007)	($1,021,671)	($1,528,586)	($4,408,323)	$17,469,261
27	Deferred True-up - Over/(Under) Recovery	$7,586,581	$7,586,581	$7,586,581	$7,586,581	$7,586,581	$7,586,581	$7,586,581	$7,586,581	$7,586,581	$7,586,581	$7,586,581	$7,586,581	$7,586,581
28	Cape Canaveral GBRA Refund Current Month	($157,544)	($157,544)	($157,544)	($157,544)	($157,544)	($157,544)	($157,544)	($157,544)	($157,544)	($157,544)	($157,544)	($157,544)	($1,890,528)
29	Prior Period True-up Provision - Collected/(Refunded) this Month	($1,298,228)	($1,298,228)	($1,298,228)	($1,298,228)	($1,298,228)	($1,298,228)	($1,298,228)	($1,298,228)	($1,298,228)	($1,298,228)	($1,298,228)	($1,298,228)	($15,578,733)
30	End of Period True-up - Over/(Under) Recovery (Sum of Lines 24 - 29)	$20,482,671	$14,169,016	$7,101,647	$1,789,177	($959,067)	($346,956)	$1,785,821	$4,429,574	$6,564,910	$6,057,995	$3,178,258	($1,275,585)	($1,275,585)
31														
32	[1] As approved on Order No. PSC-2016-0547-FOF-EI.													

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD: JANUARY 2017 THROUGH DECEMBER 2017

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	CCR True Up Line	Actual	Actual/Estimated	$ Dif. CCR - 2017 Actual/Estimated True-up	% Dif. CCR - 2017 Actual/Estimated True-up
1	Payments to Non-cogenerators	$71,986,698	$74,094,029	($2,107,332)	(2.84%)
2	Payments to Co-generators	$2,537,640	$2,537,640	$0	0.00%
3	Cedar Bay Transaction - Reg Asset - Amort & Return	$129,294,081	$129,294,081	$0	0.00%
4	Cedar Bay Transaction - Reg Liability - Amort & Return	($1,234,722)	($1,229,756)	($4,966)	0.40%
5	Indiantown Transaction - Regulatory Asset - Amortization and Return	$89,421,413	$89,421,413	$0	0.00%
6	SJRPP Suspension Accrual	($9,083,880)	($9,083,880)	$0	0.00%
7	Return on SJRPP Suspension Liability	($1,330,072)	($1,330,072)	$0	(0.00%)
8	Incremental Plant Security Costs-Order No. PSC-02-1761 (O&M)	$35,336,018	$38,983,261	($3,647,243)	(9.36%)
9	Incremental Plant Security Costs-Order No. PSC-02-1761 (Capital)	$2,669,243	$2,700,801	($31,558)	(1.17%)
10	Incremental Nuclear NRC Compliance Costs O&M	$2,423,522	$1,531,958	$891,563	58.20%
11	Incremental Nuclear NRC Compliance Costs Capital	$11,671,842	$11,639,768	$32,074	0.28%
12	Transmission of Electricity by Others	$824,059	$930,063	($106,004)	(11.40%)
13	Transmission Revenues from Capacity Sales	($7,328,291)	($6,708,353)	($619,938)	9.24%
14	Total (Lines 1 through 13)	$327,187,550	$332,780,954	($5,593,404)	(1.68%)
15					
16	Jurisdictional Separation Factor (1)	95.04658%	95.04658%		
17	Jurisdictional Capacity Charges	$310,980,577	$316,296,916	($5,316,339)	(1.68%)
18					
19	CCR Revenues	$284,597,039	$292,116,783	($7,519,744)	(2.57%)
20	Prior Period True-up Provision	$15,578,733	$15,578,733	$0	0.00%
21	Cape Canaveral GBRA Refund	$1,890,528	$1,890,528	$0	0.00%
22	CCR Revenues Applicable to Curr Pd (Net of Revenue Taxes)	$302,066,300	$309,586,044	($7,519,744)	(2.43%)
23					
24	True-up Provision for Month - Over/(Under) Recovery (Line 22 - Line 17)	($8,914,277)	($6,710,872)	($2,203,405)	32.83%
25	Interest Provision for the Month	$52,111	$61,513	($9,402)	(15.29%)
26	True-up & Interest Provision BOM - Over/(Under) Recovery	$17,469,261	$17,469,261	$0	0.00%
27	Deferred True-up - Over/(Under) Recovery	$7,586,581	$7,586,581	$0	0.00%
28	Cape Canaveral GBRA Refund Current Month	($1,890,528)	($1,890,528)	$0	0.00%
29	Prior Period True-up Provision - Collected/(Refunded) this Month	($15,578,733)	($15,578,733)	$0	0.00%
30	End of Period True-up - Over/(Under) Recovery (Sum of Lines 24 - 29)	($1,275,585)	$937,222	($2,212,807)	(236.10%)
31					
32	(1) As approved on Order No. PSC-2016-0547-FOF-EI.				

Florida Power & Light Company
Schedule A12 - Capacity Costs
Page 1 of 2

For the Month of **Dec-17**

Contract	Capacity MW	Term Start	Term End	Contract Type
Indiantown	330	12/22/1995	12/1/2025	QF
Broward South - 1991 Agreement	3.5	1/1/1993	12/31/2026	QF

QF = Qualifying Facility

	January	February	March	April	May	June	July	August	September	October	November	December	Year-to-date
ICL	1,233,346	2,543											1,235,889
BS-NEG '91	97,817	98,452	110,082	110,600	110,600	110,600	110,600	110,600	110,600	110,600	110,600	110,600	1,301,751
Total	1,331,163	100,995	110,082	110,600	110,600	110,600	110,600	110,600	110,600	110,600	110,600	110,600	2,537,640

Florida Power & Light Company
Schedule A12 - Capacity Costs
Page 2 of 2

For the Month of Dec-17

Contract	Counterparty	Identification	Contract Start Date	Contract End Date
1	JEA - SJRPP	Other Entity	April, 1982	September 30, 2021
2	Solid Waste Authority - 40 MW	Other Entity	January, 2012	March 31, 2032
3	Solid Waste Authority - 70 MW	Other Entity	July, 2015	May 31, 2034

2017 Capacity in MW

Contract	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	375	375	375	375	375	375	375	375	375	375	375	375
2	40	40	40	40	40	40	40	40	40	40	40	40
3	70	70	70	70	70	70	70	70	70	70	70	70
Total	485	485	485	485	485	485	485	485	485	485	485	485

2017 Capacity in Dollars

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total	5,766,501	6,108,331	7,331,333	6,885,779	7,218,840	5,809,218	6,018,687	5,728,777	6,303,387	5,270,026	4,872,922	4,672,896

Year-to-date Short Term Capacity Payments	71,986,698 [1]

Contract	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3												

True ups												
1	(359,124)	67,968	121,713	22,827	416,058	(608,260)	(317,941)	(382,365)	(152,217)	(190,351)	(396,126)	(307,985)
2												
3												

(1) Total capacity costs do not include payments for the Solid Waste Authority - 70 MW unit. Capacity costs for this unit were recovered through the Energy Conservation Cost Recovery Clause in 2014, consistent with Commission Order No. PSC-11-0293-FOF-EU issued in Docket No. 110018-EU on July 6, 2011.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
INCREMENTAL SECURITY
Return on Capital Investments, Depreciation and Taxes
FOR THE PERIOD: JANUARY 2017 THROUGH DECEMBER 2017

Line No.	Line	Beginning of Period	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	Total
1	Investments														
2	a.Expenditures/Additions		$107,693	$209,117	$314,076	$603,220	$842,220	($490,496)	$2,026,981	($275,163)	$291,739	$737,942	$870,727	($6,198,568)	($960,511)
3	b.Clearings to Plant		$13,535	($1,371)	$47,368	$221,213	($984,166)	$1,180,286	$5,750	$985,469	$686,597	$190,371	$4,122	$8,621,947	$10,971,120
4	c.Retirements														
5	d.Other					$222,668	$494				$84	($704)	($316)	($11,384)	$210,842
6															
7	Plant-In-Service/Depreciation Base	$11,686,654	$11,700,189	$11,698,818	$11,746,186	$11,967,399	$10,983,234	$12,163,520	$12,169,269	$13,154,738	$13,841,335	$14,031,706	$14,035,828	$22,657,775	N/A
8	Less: Accumulated Depreciation	$363,997	$407,824	$451,667	$495,578	$762,518	$806,170	$849,463	$894,302	$940,408	$990,373	$1,039,192	$1,088,682	$1,153,043	N/A
9	CWIP - Non Interest Bearing	$8,492,629	$8,600,322	$8,809,439	$9,123,515	$9,726,735	$10,568,955	$10,078,459	$12,105,440	$11,830,277	$12,122,017	$12,859,959	$13,730,686	$7,532,118	N/A
10															
11	Net Investment (Lines 7 - 8 + 9)	$19,815,286	$19,892,688	$20,056,589	$20,374,123	$20,931,616	$20,746,018	$21,392,515	$23,380,408	$24,044,608	$24,972,979	$25,852,473	$26,677,831	$29,036,850	N/A
12															
13	Average Net Investment		$19,853,987	$19,974,638	$20,215,356	$20,652,869	$20,838,817	$21,069,267	$22,386,462	$23,712,508	$24,508,793	$25,412,726	$26,265,152	$27,857,340	N/A
14															
15	Return on Average Net Investment														
16	a.Equity Component grossed up for taxes [a]		$129,315	$130,101	$131,669	$134,519	$135,730	$137,231	$146,542	$155,223	$160,435	$166,353	$171,933	$182,355	$1,781,405
17	b.Debt Component (Line 13 x debt rate x 1/12) [b]		$23,136	$23,276	$23,557	$24,067	$24,283	$24,552	$25,024	$26,506	$27,396	$28,406	$29,359	$31,139	$310,701
18															
19	Investment Expenses														
20	a.Depreciation		$43,826	$43,844	$43,911	$44,271	$43,158	$43,292	$44,839	$46,106	$48,814	$49,523	$49,807	$75,745	$577,137
21	b.Amortization														
22	c.Other														
23															
24	Total System Recoverable Costs (Lines 15 & 19)		$196,277	$197,221	$199,137	$202,857	$203,171	$205,075	$216,405	$227,835	$236,645	$244,281	$251,099	$289,239	$2,669,243
25															
26															
27															

28 [a] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. - Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI
29 and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. - Dec. 2017 period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.
30 [b] The Debt Component for the Jan. - Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI, and the Debt Component for the Jul. - Dec. 2017 period is 1.3413%
31 based on the May 2017 ROR Surveillance Report and reflects a 10.55% ROE, per FPSC Order No. PSC-2016-0560-PAA-EI.
32
33 Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
INCREMENTAL NUCLEAR NRC COMPLIANCE
Return on Capital Investments, Depreciation and Taxes
FOR THE PERIOD: JANUARY 2017 THROUGH DECEMBER 2017

Line No.	Line	Beginning of Period	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	Total
1	Investments														
2	a.Expenditures/Additions		$952		$1,682,724	($298,274)		$14,332	$4,701	$614	$57,173	($459,851)	$1,142,842	($1,474,328)	$670,885
3	b.Clearings to Plant		$39,485	($54,336)	$32,219	$2,030,862	$104,820	$107,501	($59,281)	($177,886)		$2,154,000	$1,146,654	$1,828,044	$7,152,081
4	c.Retirements									($178,821)					($178,821)
5	d.Other										($12,701)	($380,716)	($5,949)	($4,833)	($404,199)
6															
7	Plant-In-Service/Depreciation Base	$84,943,875	$84,983,360	$84,929,024	$84,961,242	$86,992,105	$87,096,925	$87,204,426	$87,145,144	$86,967,259	$86,967,259	$89,121,258	$90,267,913	$92,095,957	N/A
8	Less: Accumulated Depreciation	$3,537,436	$3,857,363	$4,177,282	$4,497,163	$4,820,912	$5,149,027	$5,477,504	$5,806,030	$5,955,446	$6,270,816	$6,222,342	$6,555,170	$6,897,009	N/A
9	CWIP - Non Interest Bearing	$1,067,677	$1,068,629	$1,068,629	$2,751,353	$2,453,079	$2,453,079	$2,467,411	$2,472,112	$2,472,726	$2,529,899	$2,070,048	$3,212,890	$1,738,561	N/A
10															
11	Net Investment (Lines 7 - 8 + 9)	$82,474,116	$82,194,626	$81,820,370	$83,215,433	$84,624,272	$84,400,977	$84,194,332	$83,811,227	$83,484,539	$83,226,342	$84,968,964	$86,925,632	$86,937,509	N/A
12															
13	Average Net Investment		$82,334,371	$82,007,498	$82,517,901	$83,919,852	$84,512,625	$84,297,655	$84,002,780	$83,647,883	$83,355,441	$84,097,653	$85,947,298	$86,931,570	N/A
14															
15	Return on Average Net Investment														
16	a.Equity Component grossed up for taxes [(a)]		$536,269	$534,140	$537,465	$546,596	$550,457	$549,057	$549,885	$547,562	$545,647	$550,506	$562,614	$569,057	$6,579,254
17	b.Debt Component (Line 13 x debt rate x 1/12) [(b)]		$95,944	$95,563	$96,158	$97,792	$98,483	$98,232	$93,898	$93,502	$93,175	$94,004	$96,072	$97,172	$1,149,995
18															
19	Investment Expenses														
20	a.Depreciation		$319,927	$319,919	$319,881	$323,749	$328,116	$328,477	$328,525	$328,237	$328,071	$332,242	$338,777	$346,672	$3,942,593
21	b.Amortization														
22	c.Other														
23															
24	Total System Recoverable Costs (Lines 15 & 19)		$952,140	$949,623	$953,504	$968,137	$977,055	$975,766	$972,308	$969,300	$966,893	$976,753	$997,462	$1,012,901	$11,671,842
25															
26															
27															

28 [(a)] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for Jan - Jun 2017 is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a
29 10.55% return on equity, and the monthly Equity Component for the Jul. - Dec. 2017 period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.
30 [(b)] The Debt Component for the Jan. - Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI, and the Debt Component for the Jul. - Dec. 2017 period is 1.3413%
31 based on the May 2017 ROR Surveillance Report and reflects a 10.55% ROE, per FPSC Order No. PSC-2016-0560-PAA-EI.
32
33 Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CEDAR BAY TRANSACTION[d]
Regulatory Asset Related to the Loss of the PPA and Income Tax Gross-Up
FOR THE PERIOD: JANUARY 2017 THROUGH DECEMBER 2017

Line No.	Line	Beginning of Period	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	Total
1	Regulatory Asset - Loss of PPA		$446,142,909	$441,495,587	$436,848,265	$432,200,943	$427,553,621	$422,906,299	$418,258,977	$413,611,655	$408,964,333	$404,317,011	$399,669,689	$395,022,367	N/A
2															
3	Regulatory Asset - Loss of PPA Amort		$4,647,322	$4,647,322	$4,647,322	$4,647,322	$4,647,322	$4,647,322	$4,647,322	$4,647,322	$4,647,322	$4,647,322	$4,647,322	$4,647,322	$55,767,864
4															
5	Unamortized Regulatory Asset - Loss of PPA	$446,142,909	$441,495,587	$436,848,265	$432,200,943	$427,553,621	$422,906,299	$418,258,977	$413,611,655	$408,964,333	$404,317,011	$399,669,689	$395,022,367	$390,375,045	N/A
6															
7	Average Unamortized Regulatory Asset - Loss of PPA		$443,819,248	$439,171,926	$434,524,604	$429,877,282	$425,229,960	$420,582,638	$415,935,316	$411,287,994	$406,640,672	$401,993,350	$397,346,028	$392,698,706	N/A
8															
9	Regulatory Asset - Income Tax Gross Up	$280,178,401	$280,178,401	$277,259,876	$274,341,351	$271,422,826	$268,504,301	$265,585,776	$262,667,251	$259,748,726	$256,830,201	$253,911,676	$250,993,151	$248,074,626	N/A
10															
11	Regulatory Asset Amortization - Income Tax Gross-Up		$2,918,525	$2,918,525	$2,918,525	$2,918,525	$2,918,525	$2,918,525	$2,918,525	$2,918,525	$2,918,525	$2,918,525	$2,918,525	$2,918,525	$35,022,300
12															
13	Unamortized Regulatory Asset - Income Tax Gross Up		$277,259,876	$274,341,351	$271,422,826	$268,504,301	$265,585,776	$262,667,251	$259,748,726	$256,830,201	$253,911,676	$250,993,151	$248,074,626	$245,156,101	N/A
14															
15	Return on Unamortized Regulatory Asset - Loss of PPA only														
16	a. Equity Component [a]		$1,775,632	$1,757,039	$1,738,446	$1,719,853	$1,701,260	$1,682,667	$1,672,434	$1,653,748	$1,635,061	$1,616,375	$1,597,689	$1,579,002	$20,129,207
17															
18	b. Equity Comp. grossed up for taxes (Line 16 / 0.61425) [b]		$2,890,732	$2,860,462	$2,830,193	$2,799,924	$2,769,654	$2,739,385	$2,722,726	$2,692,304	$2,661,883	$2,631,461	$2,601,040	$2,570,618	$32,770,381
19															
20	c. Debt Component (Line 7 * debt rate / 12) [c]		$517,183	$511,767	$506,352	$500,936	$495,520	$490,105	$464,932	$459,738	$454,543	$449,348	$444,153	$438,959	$5,733,536
21															
22	Total Return Requirements (Line 18 + 20)		$3,407,914	$3,372,229	$3,336,544	$3,300,860	$3,265,175	$3,229,490	$3,187,658	$3,152,042	$3,116,426	$3,080,809	$3,045,193	$3,009,577	$38,503,917
23	Total Recoverable Costs (Line 3 + 11 + 22)		$10,973,761	$10,938,076	$10,902,391	$10,866,707	$10,831,022	$10,795,337	$10,753,505	$10,717,889	$10,682,273	$10,646,656	$10,611,040	$10,575,424	$129,294,081

24
25
26 [a] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for Jan - Jun 2017 is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a
27 10.55% return on equity, and the monthly Equity Component for the Jul. - Dec. 2017 period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.
28 [b] Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35%.
29 [c] The Debt Component for the Jan. - Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI, and the Debt Component for the Jul. - Dec. 2017 period is 1.3413% based on the May 2017 ROR Surveillance Report and reflects a 10.55% ROE,
30 per FPSC Order No. PSC-2016-0560-PAA-EI.
31 [d] Recovery of the Cedar Bay Transaction is based on the settlement agreement approved by the FPSC in Docket No. 150075-EI at the special agenda on August 27, 2015.
32
33 Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CEDAR BAY TRANSACTION [d]
Regulatory Liability - Book/Tax Timing Difference Associated to Plant Asset
FOR THE PERIOD JANUARY 2017 THROUGH DECEMBER 2017

Line No.	Line	Beginning of Period	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	Total
1	Regulatory Liability - Book/Tax Timing Difference		($5,843,365)	($5,782,497)	($5,721,629)	($5,660,761)	($5,599,893)	($5,539,025)	($5,478,157)	($5,417,289)	($5,356,421)	($5,295,553)	($5,234,685)	($5,173,817)	N/A
2															
3	Regulatory Liability Amortization		$60,868	$60,868	$60,868	$60,868	$60,868	$60,868	$60,868	$60,868	$60,868	$60,868	$60,868	$60,868	$730,416
4															
5	Unamortized Regulatory Liability - Book/Tax Timing Diff	($5,843,365)	($5,782,497)	($5,721,629)	($5,660,761)	($5,599,893)	($5,539,025)	($5,478,157)	($5,417,289)	($5,356,421)	($5,295,553)	($5,234,685)	($5,173,817)	($5,112,949)	N/A
6															
7	Average Unamortized Regulatory Liability - Book/Tax Timing Difference		($5,812,931)	($5,752,063)	($5,691,195)	($5,630,327)	($5,569,459)	($5,508,591)	($5,447,723)	($5,386,855)	($5,325,987)	($5,265,119)	($5,204,251)	($5,143,383)	N/A
8															
9	Return on Unamortized Regulatory Liability - Book/Tax Timing Difference														
10															
11	a. Equity Component [a]		($23,256)	($23,013)	($22,769)	($22,526)	($22,282)	($22,039)	($21,905)	($21,660)	($21,415)	($21,171)	($20,926)	($20,681)	($263,643)
12															
13	b. Equity Comp. grossed up for taxes (Line 11 / 0.61425) [b]		($37,861)	($37,465)	($37,069)	($36,672)	($36,276)	($35,879)	($35,661)	($35,263)	($34,864)	($34,466)	($34,067)	($33,669)	($429,211)
14															
15	c. Debt Component (Line 7 * 1.4904% / 12) [c]		($6,774)	($6,703)	($6,632)	($6,561)	($6,490)	($6,419)	($6,089)	($6,021)	($5,953)	($5,885)	($5,817)	($5,749)	($75,095)
16															
17	Total Return Requirements (Line 13 + 15)		($44,635)	($44,168)	($43,700)	($43,233)	($42,766)	($42,298)	($41,750)	($41,284)	($40,817)	($40,351)	($39,885)	($39,418)	($504,306)
18	Total Recoverable Costs (Line 17 - 3)		($105,503)	($105,036)	($104,568)	($104,101)	($103,634)	($103,166)	($102,618)	($102,152)	($101,685)	($101,219)	($100,753)	($100,286)	($1,234,722)

19
20
21 [a] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for Jan - Jun 2017 is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a
22 10.55% return on equity, and the monthly Equity Component for the Jul. - Dec. 2017 period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.
23 [b] Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35%.
24 [c] The Debt Component for the Jan. - Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI, and the Debt Component for the Jul. - Dec. 2017 period is 1.3413%
25 based on the May 2017 ROR Surveillance Report and reflects a 10.55% ROE, per FPSC Order No. PSC-2016-0560-PAA-EI.
26 [d] Recovery of the Cedar Bay Transaction is based on the settlement agreement approved by the FPSC in Docket No. 20150075-EI, Order No. PSC-2015-0401-AS-EI.
27
28 Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
INDIANTOWN TRANSACTION[d]
Regulatory Asset Related to the Loss of the PPA and Income Tax Gross-Up
FOR THE PERIOD JANUARY 2017 THROUGH DECEMBER 2017

Line No.	Line	Beginning of Period	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	Total
1	Regulatory Asset - Loss of PPA		$451,500,000	$447,319,444	$443,138,889	$438,958,333	$434,777,778	$430,597,222	$426,416,667	$422,236,111	$418,055,556	$413,875,000	$409,694,444	$405,513,889	N/A
2															
3	Regulatory Asset - Loss of PPA Amort		$4,180,556	$4,180,556	$4,180,556	$4,180,556	$4,180,556	$4,180,556	$4,180,556	$4,180,556	$4,180,556	$4,180,556	$4,180,556	$4,180,556	$50,166,667
4															
5	Unamortized Regulatory Asset - Loss of PPA	$451,500,000	$447,319,444	$443,138,889	$438,958,333	$434,777,778	$430,597,222	$426,416,667	$422,236,111	$418,055,556	$413,875,000	$409,694,444	$405,513,889	$401,333,333	N/A
6															
7	Average Unamortized Regulatory Asset - Loss of PPA		$449,409,722	$445,229,167	$441,048,611	$436,868,056	$432,687,500	$428,506,944	$424,326,389	$420,145,833	$415,965,278	$411,784,722	$407,604,167	$403,423,611	N/A
8															
9	Return on Unamortized Regulatory Asset - Loss of PPA only														
10	a. Equity Component [a]		$1,797,998	$1,781,273	$1,764,547	$1,747,822	$1,731,096	$1,714,371	$1,706,174	$1,689,364	$1,672,555	$1,655,745	$1,638,936	$1,622,126	$20,522,007
11															
12	b. Equity Comp. grossed up for taxes (Line 10 / 0.61425) [b]		$2,927,144	$2,899,915	$2,872,686	$2,845,457	$2,818,227	$2,790,998	$2,777,654	$2,750,288	$2,722,922	$2,695,556	$2,668,190	$2,640,824	$33,409,861
13															
14	c. Debt Component (Line 7 * debt rate / 12) [c]		$523,697	$518,826	$513,954	$509,082	$504,211	$499,339	$474,312	$469,639	$464,966	$460,293	$455,620	$450,947	$5,844,886
15															
16	Total Return Requirements (Line 12 + 14)		$3,450,841	$3,418,741	$3,386,640	$3,354,539	$3,322,438	$3,290,337	$3,251,966	$3,219,927	$3,187,888	$3,155,849	$3,123,810	$3,091,771	$39,254,746
17	Total Recoverable Costs (Line 3 + 16)		$7,631,397	$7,599,296	$7,567,195	$7,535,095	$7,502,994	$7,470,893	$7,432,522	$7,400,483	$7,368,443	$7,336,404	$7,304,365	$7,272,326	$89,421,413

18
19
20 [a] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for Jan - Jun 2017 is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a
21 10.55% return on equity, and the monthly Equity Component for the Jul. - Dec. 2017 period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.
22 [b] Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35%.
23 [c] The Debt Component for the Jan. - Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI, and the Debt Component for the Jul. - Dec. 2017 period is 1.3413%
24 based on the May 2017 ROR Surveillance Report and reflects a 10.55% ROE, per FPSC Order No. PSC-2016-0560-PAA-EI.
25 [d] Recovery of the Indiantown Transaction is based on the settlement agreement approved by the FPSC in Docket No. 20160154-EI, Order No. PSC-2016-0506-FOF-EI.
26
27 Totals may not add due to rounding

FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES

Equity @ 10.55%	CAPITAL STRUCTURE AND COST RATES PER 2017 TEST YEAR RATE CASE KO-20 EXHIBIT @ 10.55% ROE				
	ADJUSTED RETAIL	RATIO	MIDPOINT COST RATES	WEIGHTED COST	PRE-TAX WEIGHTED COST
LONG_TERM_DEBT	9,420,954,129	29.025%	4.60%	1.33%	1.33%
SHORT_TERM_DEBT	512,545,348	1.579%	1.99%	0.03%	0.03%
PREFERRED_STOCK	0	0.000%	0.00%	0.00%	0.00%
CUSTOMER_DEPOSITS	414,102,244	1.276%	2.04%	0.03%	0.03%
COMMON_EQUITY	14,704,264,823	45.303%	10.55%	4.78%	7.78%
DEFERRED_INCOME_TAX	7,297,546,484	22.483%	0.00%	0.00%	0.00%
INVESTMENT_TAX_CREDITS					
ZERO COST	0	0.000%	0.00%	0.00%	0.00%
WEIGHTED COST	108,530,479	0.334%	8.23%	0.03%	0.04%
TOTAL	$32,457,943,507	100.00%		6.1993%	9.21%

	CALCULATION OF THE WEIGHTED COST FOR CONVERTIBLE INVESTMENT TAX CREDITS (C-ITC) (a)				
	ADJUSTED RETAIL	RATIO	COST RATE	WEIGHTED COST	PRE TAX COST
LONG TERM DEBT	$9,420,954,129	39.05%	4.599%	1.796%	1.796%
PREFERRED STOCK	0	0.00%	0.000%	0.000%	0.000%
COMMON EQUITY	14,704,264,823	60.95%	10.550%	6.430%	10.468%
TOTAL	$24,125,218,952	100.00%		8.226%	12.264%
RATIO					

DEBT COMPONENTS:	
LONG TERM DEBT	1.3349%
SHORT TERM DEBT	0.0314%
CUSTOMER DEPOSITS	0.0261%
TAX CREDITS -WEIGHTED	0.0060%
TOTAL DEBT	**1.3984%**
EQUITY COMPONENTS:	
PREFERRED STOCK	0.0000%
COMMON EQUITY	4.7794%
TAX CREDITS -WEIGHTED	0.0215%
TOTAL EQUITY	**4.8009%**
TOTAL	6.1993%
PRE-TAX EQUITY	7.8159%
PRE-TAX TOTAL	9.2143%

Note:

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

FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES

Equity @ 10.55%

CAPITAL STRUCTURE AND COST RATES PER MAY 2017 EARNINGS SURVEILLANCE REPORT

	ADJUSTED RETAIL	RATIO	MIDPOINT COST RATES	WEIGHTED COST	PRE-TAX WEIGHTED COST
LONG_TERM_DEBT	8,578,170,782	27.773%	4.53%	1.26%	1.26%
SHORT_TERM_DEBT	876,957,343	2.839%	1.76%	0.05%	0.05%
PREFERRED_STOCK	0	0.000%	0.00%	0.00%	0.00%
CUSTOMER_DEPOSITS	421,323,778	1.364%	2.09%	0.03%	0.03%
COMMON_EQUITY	14,087,418,183	45.610%	10.55%	4.81%	7.83%
DEFERRED_INCOME_TAX	6,860,621,618	22.212%	0.00%	0.00%	0.00%
INVESTMENT_TAX_CREDITS					
ZERO COST	0	0.000%	0.00%	0.00%	0.00%
WEIGHTED COST	62,115,684	0.201%	8.27%	0.02%	0.02%
TOTAL	$30,886,607,389	100.00%		6.17%	9.20%

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

	ADJUSTED RETAIL	RATIO	COST RATE	WEIGHTED COST	PRE TAX COST
LONG TERM DEBT	$8,578,170,782	37.85%	4.534%	1.716%	1.716%
PREFERRED STOCK	0	0.00%	0.000%	0.000%	0.000%
COMMON EQUITY	14,087,418,183	62.15%	10.550%	6.557%	10.675%
TOTAL	$22,665,588,966	100.00%		8.273%	12.391%
RATIO					

DEBT COMPONENTS:

LONG TERM DEBT	1.2592%
SHORT TERM DEBT	0.0501%
CUSTOMER DEPOSITS	0.0285%
TAX CREDITS -WEIGHTED	0.0035%
TOTAL DEBT	**1.3413%**

EQUITY COMPONENTS:

PREFERRED STOCK	0.0000%
COMMON EQUITY	4.8119%
TAX CREDITS -WEIGHTED	0.0132%
TOTAL EQUITY	**4.8251%**
TOTAL	6.1663%
PRE-TAX EQUITY	7.8552%
PRE-TAX TOTAL	9.1965%

Note:

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

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD J. YUPP

DOCKET NO. 20180001-EI

MARCH 2, 2018

Q. Please state your name and address.

A. My name is Gerard J. Yupp. My business address is 700 Universe Boulevard, Juno Beach, Florida, 33408.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power and Light Company ("FPL") as Senior Director of Wholesale Operations in the Energy Marketing and Trading Division.

Q. Please summarize your educational background and professional experience.

A. I graduated from Drexel University with a Bachelor of Science Degree in Electrical Engineering in 1989. I joined the Protection and Control Department of FPL in 1989 as a Field Engineer where I was responsible for the installation, maintenance, and troubleshooting of protective relay equipment for generation, transmission and distribution facilities. While employed by FPL, I earned a Masters of Business Administration degree from Florida Atlantic University in 1994. In 1996, I joined the Energy Marketing and Trading Division ("EMT") of FPL as a real-time power trader. I progressed through several power trading positions and assumed the lead role for power trading in 2002. In 2004, I became the Director of Wholesale Operations and natural gas and fuel oil procurement and operations were added to my responsibilities. I have been in my current role since 2008. On the operations side, I am responsible for the procurement and management of all natural gas and fuel oil for FPL, as well as all short-term power trading activity. Finally, I am responsible for the oversight of FPL's optimization activities associated with the Incentive Mechanism.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the 2017 results of FPL's activities under the Incentive Mechanism that was originally approved by Order No. PSC-13-0023-S-EI, dated January 14, 2013, in Docket No. 120015-EI and approved for continuation with certain modifications by Order No. PSC-16-0560-AS-EI, dated December 15, 2016, in Docket No. 160021-EI.

Q. Have you prepared or caused to be prepared under your supervision, direction and control any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits:

- GJY-1, consisting of 4 pages:
    - Page 1 – Total Gains Schedule
    - Page 2 – Wholesale Power Detail
    - Page 3 – Asset Optimization Detail
    - Page 4 – Incremental Optimization Costs

Q. Please provide an overview of the Incentive Mechanism.

A. The Incentive Mechanism is an expanded optimization program that is designed to create additional value for FPL's customers while also providing an incentive to FPL if certain customer-value thresholds are achieved. The Incentive Mechanism includes gains from wholesale power sales and savings from wholesale power purchases, as well as gains from other forms of asset optimization. These other forms of asset optimization include, but are not limited to, natural gas storage optimization, natural gas sales, capacity releases of natural gas transportation, capacity releases of electric transmission and potentially capturing additional value through a third party in the form of an Asset Management Agreement ("AMA").

Q. Please describe the modifications that were made to the Incentive Mechanism in FPL's 2016 rate case and approved by Order No. PSC-16-0560-AS-EI.

A. There were two specific modifications made to the Incentive Mechanism in FPL's 2016 rate case. First, the sharing threshold was reduced from $46 million to $40 million. The sharing intervals and percentages remained unchanged from the original Incentive Mechanism. Under the modified Incentive Mechanism, customers will continue to receive 100% of the gains up to the new sharing threshold of $40 million. Incremental gains above $40 million will continue to be shared between FPL and customers as follows: customers receive 40% and FPL receives 60% of the incremental gains between $40 million and $100 million; and customers receive 50% and FPL receives 50% of all incremental gains above $100 million.

The second modification that was made to the Incentive Mechanism involved variable power plant O&M costs. Under the original Incentive Mechanism, FPL was allowed to recover variable power plant O&M costs incurred to make wholesale sales above 514,000 MWh (the level of wholesale sales that were assumed in forecasting FPL's 2013 test year power plant O&M costs in the MFRs filed in FPL's 2012 rate case). Under the modified Incentive Mechanism, FPL will net economy sales and purchases and recover the net amount of variable power plant O&M incurred during the year. For example, if economy purchases are greater than economy sales, customers will receive a credit for the net variable power plant O&M that has been saved during the year. The per-MWh variable power plant O&M rate that FPL will use to calculate these costs, as described in FPL's 2017 Test Year MFR's filed with the 2016 Rate Petition will be $0.65/MWh. FPL continues to be allowed to recover reasonable and prudent incremental O&M costs incurred in implementing the expanded optimization program under the Incentive Mechanism, including incremental personnel, software and associated hardware costs.

Q. Please summarize the activities and results of the Incentive Mechanism for 2017.

A. FPL's activities under the Incentive Mechanism in 2017 delivered $43,861,831 in total gains. During 2017, FPL's activities under the Incentive Mechanism included wholesale power purchases and sales, natural gas sales in the market and production areas, gas storage utilization, and the capacity release of firm natural gas transportation. Additionally, FPL entered into several AMAs related to a small portion of upstream gas transportation during 2017. The total gains of $43,861,831 exceeded the sharing threshold of $40 million. Therefore, the gains above $40 million will be shared between customers and FPL, 40% and 60%, respectively. Exhibit GJY-1, Page 1, shows monthly gain totals, threshold levels and the final gains allocation for 2017.

Q. Please provide the details of FPL's wholesale power activities under the Incentive Mechanism for 2017.

A. The details of FPL's 2017 wholesale power sales and purchases are shown separately on Page 2 of Exhibit GJY-1. FPL had gains of $17,277,542 on wholesale sales and savings of $7,821,480 on wholesale purchases for the year.

Q. Please provide the details of FPL's asset optimization activities under the Incentive Mechanism for 2017.

A. The details of FPL's 2017 asset optimization activities are shown on Page 3 of Exhibit GJY-1. FPL had a total of $18,762,809 of gains that were the result of seven different forms of asset optimization.

Q. Did FPL engage in any new forms of asset optimization during 2017?

A. No. FPL did not engage in any new forms of asset optimization activities during 2017.

Q. Did FPL incur incremental O&M expenses related to the operation of the Incentive Mechanism in 2017?

A. Yes. FPL incurred personnel expenses of $425,123 related to an additional two and one-half personnel required to support FPL's expanded activities under the

Incentive Mechanism. FPL also incurred $278,801 in expenses related to licensing fees of OATI WebTrader software and a collaborative working engagement with Accenture LLP. In total, FPL incurred incremental O&M expenses related to the operation of the Incentive Mechanism of $703,923 in 2017.

On the variable power plant O&M side, FPL's actual net economy power sales totaled 1,341,059 MWh (i.e., 1,962,498 MWh of economy sales, less 621,439 MWh of economy purchases). This resulted in net variable power plant O&M costs of $871,688 for 2017.

Q. Overall, were FPL's activities under the Incentive Mechanism successful in 2017?

A. Yes. FPL's activities under the Incentive Mechanism were highly successful in 2017. On the wholesale power side, suitable market conditions in the winter period helped drive strong wholesale power sales, and high demand during the summer peak period provided the opportunity to purchase power from the market to avoid running more expensive generation. Overall, FPL was able to consistently capitalize on power market opportunities throughout the year to deliver slightly more than $25 million in customer benefits. Asset optimization activities related to natural gas resulted in significant customer benefits of more than $18.5 million. In total, these activities delivered $43,861,831 of gains, which contrast very favorably to the total optimization expenses (personnel and variable power plant O&M) of $1,575,612.

Q. Does this conclude your testimony?

A. Yes it does.

TOTAL GAINS SCHEDULE
Actual for the Period of: January 2017 through December 2017

TABLE 1

(1) Month	(2) Wholesale Sales Gains ($)	(3) Wholesale Purchases Savings ($)	(4) Asset Optimization Gains ($)	(5) Total Monthly Gains ($) (2)+(3)+(4)	(6) **Threshold 1** Gains ≤ $30M ($)	(7) **Threshold 2** $30M > Gains ≤ $40M ($)	(8) **Threshold 3** $40M > Gains ≤ $100M ($)	(9) **Threshold 4** Gains > $100M ($)
January	3,872,450	474	1,032,914	4,905,838	4,905,838	0	0	0
February	2,943,666	53,941	1,168,100	4,165,706	4,165,706	0	0	0
March	1,513,177	172,750	1,120,311	2,806,239	2,806,239	0	0	0
April	959,535	625,111	1,121,805	2,706,450	2,706,450	0	0	0
May	978,003	1,473,946	1,975,986	4,427,935	4,427,935	0	0	0
June	1,034,596	1,904,629	1,656,384	4,595,609	4,595,609	0	0	0
July	754,247	604,525	1,744,266	3,103,038	3,103,038	0	0	0
August	720,150	2,423,262	2,069,815	5,213,228	3,289,185	1,924,043	0	0
September	1,196,534	304,114	1,851,678	3,352,326	0	3,352,326	0	0
October	455,254	234,188	1,220,333	1,909,776	0	1,909,776	0	0
November	820,518	24,540	1,417,614	2,262,672	0	2,262,672	0	0
December	2,029,412	0	2,383,603	4,413,015	0	551,184	3,861,831	0
Total	**17,277,542**	**7,821,480**	**18,762,809**	**43,861,831**	**30,000,000**	**10,000,000**	**3,861,831**	**0**

TABLE 2

(1) Month	(2) **Threshold 1** Gains ≤ $30M 100% Customer Benefit ($)	(3) **Threshold 2** $30M > Gains ≤ $40M 100% Customer Benefit ($)	(4) **Threshold 3** $40M > Gains ≤ $100M 40% Customer Benefit ($)	(5) **Threshold 3** $40M > Gains ≤ $100M 60% FPL Benefit ($)	(6) **Threshold 4** Gains > $100M 50% Customer Benefit ($)	(7) **Threshold 4** Gains > $100M 50% FPL Benefit ($)	(8) **Total** Customer Benefits ($)	(9) **Total** FPL Benefits ($)
January	4,905,838	0	0	0	0	0	4,905,838	0
February	4,165,706	0	0	0	0	0	4,165,706	0
March	2,806,239	0	0	0	0	0	2,806,239	0
April	2,706,450	0	0	0	0	0	2,706,450	0
May	4,427,935	0	0	0	0	0	4,427,935	0
June	4,595,609	0	0	0	0	0	4,595,609	0
July	3,103,038	0	0	0	0	0	3,103,038	0
August	3,289,185	1,924,043	0	0	0	0	5,213,228	0
September	0	3,352,326	0	0	0	0	3,352,326	0
October	0	1,909,776	0	0	0	0	1,909,776	0
November	0	2,262,672	0	0	0	0	2,262,672	0
December	0	551,184	1,544,732	2,317,099	0	0	2,095,916	2,317,099
Total	**30,000,000**	**10,000,000**	**1,544,732**	**2,317,099**	**0**	**0**	**41,544,732**	**2,317,099**

WHOLESALE POWER DETAIL
Actual for the Period of: January 2017 through December 2017

Wholesale Sales - Table 1

(1) Month	(2) OS Wholesale Sales (MWh)	(3) FCBBS Wholesale Sales (MWh)	(4) Total Wholesale Sales (MWh)	(5) OS Gross Gains ($)	(6) FCBBS Gross Gains ($)	(7) Third-Party Transmission Costs ($)	(8) Variable Power Plant O&M Costs ($)	(9) Power Option Premiums ($)	(10) Total Net Wholesale Sales Gains ($)
	Schedule A6	Schedule A6	(2) + (3)	Schedule A6	Schedule A6	Schedule A6	Schedule A6	*CCRC	(5)+(6)+(7)+(8)+(9)
January	512,857	75	512,932	4,073,160	464	(1,866)	(333,406)	134,098	3,872,450
February	431,619	74	431,693	3,099,468	247	(6,199)	(280,600)	130,750	2,943,666
March	255,482	50	255,532	1,697,280	176	(35,481)	(166,096)	17,298	1,513,177
April	118,563	494	119,057	918,165	2,095	383	(77,387)	116,280	959,535
May	39,543	99	39,642	521,166	666	0	(25,767)	481,938	978,003
June	55,425	49	55,474	652,722	260	(3,868)	(36,058)	421,540	1,034,596
July	45,392	49	45,441	464,141	346	(44,402)	(29,537)	363,698	754,247
August	39,785	0	39,785	443,186	0	(2,473)	(25,860)	305,298	720,150
September	54,276	0	54,276	932,734	0	(24,961)	(35,279)	324,040	1,196,534
October	62,716	0	62,716	464,241	0	(6,081)	(40,765)	37,860	455,254
November	113,293	0	113,293	877,409	0	10	(73,640)	16,740	820,518
December	232,657	0	232,657	2,182,494	0	(19,152)	(151,227)	17,298	2,029,412
Total	**1,961,608**	**890**	**1,962,498**	**16,326,166**	**4,254**	**(144,092)**	**(1,275,624)**	**2,366,838**	**17,277,542**

Wholesale Purchases - Table 2

(1) Month	(2) OS Wholesale Purchases (MWh)	(3) FCBBS Wholesale Purchases (MWh)	(4) Total Wholesale Purchases (MWh)	(5) OS Savings ($)	(6) FCBBS Savings ($)	(7) Total Schedule A9 Savings ($)	(8) Capacity Purchases (MWh)	(9) Net Capacity Purchases Savings ($)	(10) Total Wholesale Purchases Savings ($)
	Schedule A9	Schedule A9	Schedule A9	Schedule A9	Schedule A9	Schedule A9	Schedule A7/A12		(7) + (9)
January	85	0	85	474	0	474	0	0	474
February	6,672	10	6,682	53,868	73	53,941	0	0	53,941
March	18,532	0	18,532	172,750	0	172,750	0	0	172,750
April	68,120	125	68,245	624,345	765	625,111	0	0	625,111
May	154,246	0	154,246	1,473,946	0	1,473,946	0	0	1,473,946
June	149,669	0	149,669	1,904,629	0	1,904,629	0	0	1,904,629
July	50,081	98	50,179	603,671	854	604,525	0	0	604,525
August	113,160	0	113,160	2,423,308	(46)	2,423,262	0	0	2,423,262
September	38,276	0	38,276	304,114	0	304,114	0	0	304,114
October	20,029	0	20,029	234,188	0	234,188	0	0	234,188
November	2,336	0	2,336	24,540	0	24,540	0	0	24,540
December	0	0	0	0	0	0	0	0	0
Total	**621,206**	**233**	**621,439**	**7,819,834**	**1,646**	**7,821,480**	**0**	**0**	**7,821,480**

ASSET OPTIMIZATION DETAIL
Actual for the Period of: January 2017 through December 2017

(1) Month	(2) Natural Gas Delivered City-Gate Sales ($)	(3) Natural Gas Production Area Sales ($)	(4) Natural Gas Capacity Release Firm Transport ($)	(5) Natural Gas Option Premiums ($)	(6) Natural Gas Storage Optimization ($)	(7) Natural Gas AMA Gains ($)	(8) NOX Emissions Sales ($)	(9) Total Asset Optimization Gains ($)
January	[redacted]							1,032,914
February	[redacted]							1,168,100
March	[redacted]							1,120,311
April	[redacted]							1,121,805
May	[redacted]							1,975,986
June	[redacted]							1,656,384
July	[redacted]							1,744,266
August	[redacted]							2,069,815
September	[redacted]							1,851,678
October	[redacted]							1,220,333
November	[redacted]							1,417,614
December	[redacted]							2,383,603
Total	**3,538,237**	**602,559**	**3,217,971**	**8,945,075**	**861,359**	**1,478,429**	**119,180**	**18,762,809**

INCREMENTAL OPTIMIZATION COSTS
Actual for the Period of: January 2017 through December 2017

(1) Month	(2) Personnel Expenses ($)	(3) Other Expenses* ($)	(4) Wholesale Sales (MWh)	(5) Wholesale Purchases (MWh)	(6) Wholesale Sales VOM ($)	(7) Wholesale Purchases VOM ($)	(8) Net VOM ($)	(9) Total Incremental O&M Expenses ($)
	Schedule A2						Schedule A2	(2) + (3) + (8)
January	34,985	0	512,932	85	333,406	(55)	333,351	368,336
February	32,162	9,560	431,693	6,682	280,600	(4,343)	276,257	317,980
March	38,154	4,780	255,532	18,532	166,096	(12,046)	154,050	196,984
April	33,038	4,920	119,057	68,245	77,387	(44,359)	33,028	70,985
May	37,496	4,780	39,642	154,246	25,767	(100,260)	(74,493)	(32,217)
June	37,114	226,106	55,474	149,669	36,058	(97,285)	(61,227)	201,993
July	35,583	4,780	45,441	50,179	29,537	(32,616)	(3,080)	37,283
August	36,185	4,774	39,785	113,160	25,860	(73,554)	(47,694)	(6,736)
September	30,290	4,780	54,276	38,276	35,279	(24,879)	10,400	45,470
October	34,948	4,774	62,716	20,029	40,765	(13,019)	27,747	67,468
November	34,976	4,774	113,293	2,336	73,640	(1,518)	72,122	111,871
December	40,192	4,774	232,657	0	151,227	0	151,227	196,193
Total	**425,123**	**278,801**	**1,962,498**	**621,439**	**1,275,624**	**(403,935)**	**871,688**	**1,575,612**

*Includes software and hardware expenses